NPCC, Inc.

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

NPCC REGIONAL STANDARDS COMMITTEE

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

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

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

Introductions and Chair's Remarks

NPCC Antitrust Compliance Guidelines

Agenda Items:

1.0 Review of Agenda

2.0 RSC Meeting Minutes

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

3.0 Drafting Team Members and Executive Tracking Summary

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

4.0 Open Action Items

4.1 Open Action Items List

5.0 Items Requiring RSC Discussion / Approval

5.1 NERC Weekly Standards Bulletin
5.2 NPCC RCC Meeting Minutes
5.3 Primary RSC Members can't serve as Alternates in other sectors
5.4 Renegotiation of Regional Delegation Agreements
5.5 Validation Testing of Minimum Vegetation Clearance Distances
5.6 NYPA Comments on CIP-002-5.1 Lessons Learned
5.7 Review of the Documents on RSC NPCC Website
5.8 Project 2007-06.2 Phase 2 of System Protection Coordination
5.9 Periodic Review Project 2010-14.2 BAL-005-0.2b and BAL-006-3

5.10 Draft ERO Event Analysis Process and Appendices – Version 3

6.0 NERC Reliability Standards

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

6.1 Currently Posted Projects

Project	Comment Period End Date	Ballot Period End Date	Standards Developer	4/22/15 Call-In
Project 2008-02.2 Phase 2 of Undervoltage Load Shedding (UVLS): Misoperations			Scott Barfield-McGinnis	
Project 2014-04 Physical Security			Stephen Crutchfield	
Project 2007-06 System Protection Coordination	5/15/15 (F)	5/15/15 (A)	Al McMeekin	
Project 2015-02 Emergency Operations Periodic Review	5/11/15 (I)		Laura Anderson Chair: David McRee	1:45PM
New Standards Balloting and Commenting System			Barbara Nutter	2:00PM
Comments: (I) – Informal; (F) – Formal **Ballots:** (I) – Initial; (A) – Additional; (F) – Final				

6.2 Ballot History (Since last RSC Meeting)

6.3 Comment Form History (Since last RSC Meeting)

7.0 NERC Drafting Team Nominations

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

7.1 Currently Posted Drafting Team Vacancies

7.1.1 None at this time

7.2 Closed Drafting Team Nominations (Since last RSC Meeting)

7.2.1 None at this time

7.3 Solicitation For Informal Development Teams

7.3.1 None at this time

8.0 NPCC Regional Reliability Standards*

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

8.1 Current Activities:

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

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

Vincent Morissette call in to present Quebec Variance on April 23, 2015

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

9.0 NPCC Non-Standards*

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

9.1 Directories:

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

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

9.1.2 Directory #3 Maintenance Criteria BPS – (Retirement Approved on 10/15/2014 effective April 1st, 2015).

9.1.3 Directory #7 SPS (Status of NERC RAS)

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

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

10.0 RSC Member Items of Interest

10.1 RSC Roster*

11.0 Standards Activity Post NERC BOT Approval*

(Since last RSC Meeting)

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

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

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

11.4 FERC Sunshine Act Meeting Notice

11.5 FERC Open Meeting Summaries

12.0 NERC Meetings

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

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

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

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

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

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

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

13.0 NERC Compliance Tools (Since last RSC Meeting)

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

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

14.0 NERC Items of Interest (Since last RSC Meeting)

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

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

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

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

14.3 Five Year ERO Performance Assessment

15.0 Other Items of Interest

15.1 2015 Regional Entity Business Plans and Budgets

15.2 NPCC Compliance Committee (CC)

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

15.3 NPCC Board of Directors Meeting (BOD)

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

16.0 Future RSC Meetings and Conference Calls

16.1 RSC 2015 Meeting Dates

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

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

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

Respectfully Submitted,

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

Northeast Power Coordinating Council, Inc. (NPCC)

Antitrust Compliance Guidelines

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

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

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

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

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

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

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NPCC REGIONAL STANDARDS COMMITTEE

AGENDA FOR MEETING #15-1
February 18, 2015 10:00 a.m. – 5:00 p.m. EST
February 19, 2015 8:00 a.m. – 3:00 p.m. EST
NextEra Energy Office
700 Universe Boulevard
Juno Beach, Florida USA
Attire: Business Casual

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

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

Attendees:

	Name	Organization	Sector (s)	Day(s)	Comment
1.	Kal Ayoub	FERC	Guest	1	Via Phone
2.	Guy Zito	Northeast Power Coordinating Council		1 & 2	
3.	Lee Pedowicz	Northeast Power Coordinating Council		1 & 2	
4.	Gerry Dunbar	Northeast Power Coordinating Council		1 & 2	Via Phone
5.	RuiDa Shu	Northeast Power Coordinating Council		1 & 2	
6.	Herb Schrayshuen	Power Advisors, LLC	Guest	1 & 2	Via Phone
7.	Silvia Parada Mitchell	NextEra Energy, LLC	4	1 & 2	
8.	Jim Grant Proxy for Greg Campoli	New York Independent System Operator	2	1 & 2	
9.	Kelly Dash	Consolidated Edison Co. of New York, Inc.	1	1 & 2	
10.	Bruce Metruck	New York Power Authority	5	1 & 2	Via Phone
11.	Kathleen Goodman	ISO-NE	2	1 & 2	Via Phone
12.	Alan MacNaughton	New Brunswick Power Corporation	1	1 & 2	

13.	Don Weaver	New Brunswick Energy and Utilities Board	Guest	1 & 2	
14.	SiTruc Phan Sector 1 Proxy for Sylvain Clermont	Hydro-Québec TransÉnergie	1/2	1 & 2	
15.	Chantal Mazza	Hydro-Québec TransÉnergie	Guest	1 & 2	Via Phone
16.	Brian Robinson	Utility Services	5	1 & 2	
17.	Brian Shanahan	National Grid	1	1 & 2	Via Phone
18.	Michael Jones	National Grid	3	1 & 2	Via Phone
19.	Payam Farahbakhsh	Hydro One Networks	1	1 & 2	
20.	Helen Lainis	Independent Electricity System Operator	2	1 & 2	
21.	Ben Wu	Orange and Rockland Utilities	1	1 & 2	
22.	Tom Neglia	Orange and Rockland Utilities	3	1 & 2	Via Phone
23.	Connie Lowe	Dominion Resources Services	4	1	Via Phone
24.	Ron Falsetti	AESI	Guest	1 & 2	

Introductions and Chair's Remarks

Guy Zito called the meeting to order at 10:00AM on Wednesday February 18, 2015.

NPCC Antitrust Compliance Guidelines

The NPCC Antitrust Compliance Guidelines were read by Lee Pedowicz.

Agenda Items:

1.0 Review of Agenda

The RSC Draft Meeting Agenda was reviewed by Guy Zito. He added sections 8.3 and 5.11 to the RSC Draft Meeting Agenda.

2.0 RSC Meeting Minutes

2.1 Approval of Minutes: Final Meeting Minutes 12-4-14.

The RSC Meeting Minutes for December 4, 2014 RSC meeting #14-5 was reviewed.

Silvia Parada Mitchell made a motion for approval.

SiTruc Phan seconded the motion.

The Meeting Minutes were approved as read.

3.0 Drafting Team Members and Executive Tracking Summary

3.1 NPCC Members on NERC Drafting Teams

Guy Zito provided updates on the drafting teams. RSC reviewed the drafting team spreadsheet and removed Vladimir Stanisic from Project 2007-11 and Kyle Russell from Project 2014-03. RSC also added Tim Kucey from PSEG to Project 2007-11.

3.2 Executive Tracking Summary

RuiDa Shu provided updates on the Executive Tracking Summary.

3.3 NERC Project Tracking Spreadsheet

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

4.0 Open Action Items

4.1 Open Action Items List

Guy Zito provided updates on the Open Action Item list. Guy Zito decided to keep the RSAW, and will provide outreach for Utility Services.

Item	Description	Owner	Due	Status
4.1	Coordination with the Compliance Committee to develop Joint Activity Action List	Greg Campoli	RSC Meeting	Ongoing Guy Zito decided to keep RSAWs for now.
4.2	NPCC outreach program development – discussion item: members provide input and opportunities for development of an outreach program	RSC	RSC Meeting	Update: Ongoing, possible outreach for Utility Services.

5.0 Items Requiring RSC Discussion / Approval

5.1 NERC Weekly Standards Bulletin

5.2 NERC RAPA Meeting

5.3 NPCC RCC Meeting Minutes

Ontario Power Generation's Pickering Units require upgrades to their protection systems to comply with Directory 4. It is planned to have the units taken off -line in 5 years, with a possible extension of another 5 years making OPG out of compliance for 10 years. TFSP did not grant the waivers and OP wants to take this to the RCC. Cost effectiveness is being taken into consideration. OPG's main reason for requesting waivers is that to be compliant the Pickering Units will have to do extensive physical modifications, (lack of physical spaces) not justified by the Units being taken out of service.

5.4 NERC Bulk Electric System Update

Herb Schrayshuen indicated that there are a few new IT tools for the BES. All data submitted was moved into the review process by January 15, 2015.

5.5 New NERC Web Page Dedicated to Canadian Resources

Guy Zito provided updates on the new website for Canadian Resources. Guy indicated that Laura Hussey from NERC will be the main contact for Canadian Resources.

5.6 Vice- Chairs and Executive Committee Members Positions

RSC elected SiTruc Phan and Bruce Metruck each to a 2 year term as a RSC Vice-chair.

Helen Lainis and Mike Jones were elected to each serve a 2 year term as an Executive Committee Member.

5.7 RSC Scope of Work

5.8 Abnormal low number of Canadian Nominations

5.9 Project 2014-03 Revisions to TOP and IRO Standards

Ben Li called in at 10:30AM on Wednesday February 18, 2015. He expressed IESO concerns. The main disagreement is on the retirement of TOP-004-2, R4 the intent of which is no longer covered in the proposed TOP-001-3. IESO feels that this could result in a reliability gap.

5.10 BARC SDT

5.11 Project 2014-04 Physical Security

There are a lot of concerns with this standard. Several members of the RSC indicated that this standard is not necessary.

6.0 NERC Reliability Standards

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

6.1 Currently Posted Projects

Project	Comment Period End Date	Ballot Period End Date	Standards Developer	2/18/15 Call-In
New Standards Balloting and Commenting System			Barbara Nutter	11:00AM
Project 2015-02 - Emergency Operations Periodic Review			Laura Anderson	2:15PM
Project 2015-03 - Periodic Review of System Operating Limit Standards			Marisa Hecht	2:00PM
Project 2015-04 - Alignment of NERC Glossary of Terms and Definitions Used in the Rules of Procedure (Appendix 2 of the Rules of Procedure)			Lacey Ourso	1:45PM
Project 2007-06.2 - System Protection Coordination			Scott Barfield McGinnis	12:45PM
Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS) PRC-004 Misop			Scott Barfield McGinnis	1:00PM
Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	3/16/15 (F)	3/16/15 (A)	Darrel Richardson	1:15PM
Comments: (I) – Informal; (F) – Formal **Ballots:** (I) – Initial; (A) – Additional; (F) – Final				

New Standards Balloting and Commenting System:

Barb Nutter from NERC called into the RSC meeting and discussed the New Standards Balloting and Commenting System.

Project 2007-06.2 – System Protection Coordination:

Scott Barfield from NERC called into the RSC meeting and provided information on some recent activities of the SDT. The SDT expects to host a webinar for outreach purposes in two weeks. The main objective is to revise the PRC-001 Standard.

Guy Zito suggested that a member of the SDT make a presentation at the NPCC's Spring Workshop.

There is a concern with TOP-001 Standard on the 30 minute response time and this issue needs to be brought to the SDT meeting. Most of the NPCC systems have dual redundancy of protection systems. The goal is to provide all the documents for the September 2015 Board meeting.

Project 2008-02 – Undervoltage Load Shedding (UVLS):

Scott Barfield also provided a brief update on Project 2008-02.

The SDT added the applicability of PRC-004. UVLS tends to trip more BES elements.

The PRC-010 Standard will include more elements.

Minor cosmetic changes were made to the language of PRC-010.

Target goal is to file with Board for its May 2015 meeting.

Project 2010-14.1 – Phase 1 of Balancing Authority Reliability-based Controls Reserves:

Darrel Richardson from NERC, Vice-chair of the SDT, and another member of the SDT called in at 1:15PM and provided some insights on Project 2010-14.1The SDT clarified the standard in response to industry concerns. The SDT tried to address the FERC directive, and eliminate any potential overlap with any TOP standards.

The SDT added the flexibility to use the contingency reserves so it's not a violation.

Project 2015-04 - Alignment of NERC Glossary of Terms and Definitions Used in the Rules Of Procedure (Appendix 2 of the Rules of Procedure):

Lacey Ourso from NERC called in at 1:45PM and provided an update on Project 2015-04.

The SDT will be meeting face-to-face February 19th, 2015 to develop a SAR for the Project.

There are approximately 25 terms or so that need to be adjusted.

Guy Zito suggested having one set of terms for all instead of two different sets.

Project 2015-03 - Periodic Review of System Operating Limit Standards:

Marisa Hecht from NERC called in at 2:00PM and provided a brief update on Project 2015-03.

She indicated that the initial conference call was on February 9th, 2015.
The first SDT face-to-face meeting is February 18-19th, 2015 in Salt Lake City.
The goal is to reaffirm, revise, or retire FAC-010, FAC-011, and FAC-014.
Plan to submit to the Board by its November 2015 meeting.

Project 2015-02 - Emergency Operations Periodic Review:
Steve Crutchfield from NERC called in at 2:15PM in place of Laura Anderson.
There are four standards to review (EOP-004-2, EOP-005-2, EOP-006-1 and EOP-008-1).
The standards are due for a five year review period.
There are also two directives for EOP-005-2.
The goal is for the SDT to produce the standard for comments by late March or early April 2015.
A change suggested by SiTruc Phan on the variance parameter from 1000MW to 2000MW.

6.1.1 SC to develop a policy for comments on NERC postings other than standards.
General comments made were that standards will be the priority instead of white papers that become Standards. RSC will do the best to review the standards related documents including guidelines and white papers as time allows and seek help from Task Forces if possible.

6.2 Ballot History (since last RSC Meeting)
Rui Da Shu reviewed the Ballot History.
Herb Schrayshuen indicated that the Project page for a completed project can be found on the NERC Standard website.

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

7.0 NERC Drafting Team Nominations

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

7.1 Currently Posted Drafting Team Vacancies
7.1.1 None at this time

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

7.3 Solicitation For Informal Development Teams
7.3.1 None at this time

8.0 NPCC Regional Reliability Standards*

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

8.1 Current Activities: RSAR for Disturbance Monitoring Standard PRC-002-NPCC-01

Guy Zito indicated that this is the preliminary step to revise or retire the NPCC Disturbance Monitoring Standard to eliminate any overlap with the continent wide standard.

Lee Pedowicz added Paul Difilippo as the RSAR requester and added minor wording changes provided by Kelly Dash.

Brian Robison made a motion for approval.

Jim Grant seconded the motion.

The RSAR for Disturbance Monitoring Standard PRC-002-NPCC-1 was approved as read.

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

8.3 PRC-006-NPCC RSAR

The RSC reviewed a tabular comparison of the GO requirements in PRC -006-NPCC-1 with the requirements of PRC-024. The comparison revealed some potential duplication among the requirements.

Action Item: Lee Pedowicz will draft an RSAR to consider revisions to PRC -006-NPCC-1 in order to eliminate GO requirements which are covered by the requirements in PRC -024. Specifically address the Quebec variance issue.

9.0 NPCC Non-Standards*

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

9.1 Directories:

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

The RSC reviewed the email message on1/26/15 provided by Gerry Dunbar.

The CO7/CP11 Working Group drafting Directory #1 has suggested removing the list of ERO Standards contained within Directory #1. The RSC will consider this question on a more global basis since each NPCC Directory contains such a list.

Mr. Dunbar took an action item to provide more information on this issue including the pros and cons of leaving the list of ERO standards in each Directory.

The RSC agreed to let the drafting of Directory #1 continue pending a final RSC decision and a response on behalf of the RSC will be provided to the CO7/CP11 Working Group by NPCC Staff.

9.1.2 Directory #3 Maintenance Criteria BPS – Retirement Approved on 10/15/2014 effective April 1st, 2015.

9.1.3 Directory #7 SPS (status of NERC RAS)

Gerry Dunbar provided background on the implementation of the Remedial Action Scheme (RAS) definition within NPCC.

The TFCP has requested that the TFSS review the existing list/database of NPCC SPS's to determine which of the SPS's on the list conform to the definition of RAS. Mr. Dunbar stated that NPCC anticipates an incremental transition to the RAS definition that will include NPCC document revision and criteria/typing review in order to ensure that NPCC's criteria remains 'not inconsistent' with the revised PRC standards.

Guy Zito added that he is observing the NERC Drafting Team and Project activities which will revise the existing SPS standards in order to minimize transition issues within NPCC.

9.2 Directory Clarifications

9.2.1 TFSP Clarification for the IESO- Market Assessment and Compliance Division (MACD). Status of TFSP Clarification--Gerry Dunbar reported that the TFSP Criteria Clarification on Directory #3 will be presented to the RCC for approval on 3/4/2015. This clarification will be the first presented to the RCC for approval in accordance with the RSC approved revisions to the NPCC Directory Manual.

10.0 RSC Member Items of Interest

10.1 RSC Roster

Members of the RSC reviewed the RSC Roster during the meeting. The RSC made the decision of replaced Greg Campoli with SiTruc Phan as the Vice-chair.
Minor editorial changes were made to the ISO-NE contact.
Alan MacNaughton requested to put a place holder for his alternate and a primary for RC since NB Power is also a RC.
Silvia Parada Mitchell indicated that she will find a new alternate for NextEra Energy, LLC.
Bruce Metruck made the request to remove Daniel Piper as NYPA's alternate contact.

11.0 Standards Activity Post NERC BOT Approval*

(Since last RSC Meeting)

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

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

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

11.4 FERC Sunshine Act Meeting Notice

11.5 FERC Open Meeting Summaries

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

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

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

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

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

13.0 NERC Compliance Tools (Since last RSC Meeting)

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

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

14.0 NERC Items of Interest (Since last RSC Meeting)

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

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

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

14.2.1 There have been no new NERC Alerts released since the last RSC meeting.

14.3 Five Year ERO Performance Assessment

15.0 Other Items of Interest

15.1 2015 Regional Entity Business Plans and Budgets

15.2 NPCC Compliance Committee (CC)

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

15.3 NPCC Board of Directors Meeting (BOD)

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

16.0 Future RSC Meetings and Conference Calls

16.1 RSC 2015 Meeting Dates

February 18th-19th, 2015 NextEra Energy Offices, Juno Beach FL
April 15th & 16th, 2015 Dominion Offices, Richmond VA
June 23rd & 24th, Saratoga NY
October 7th & 8th, Montreal Quebec
December 3rd & 4th, Albany NY

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

January 16	January 30	February 13
March 6	March 20	April 3
May 1	May 15	May 29
June 12	July 10	July 23
August 14	August 28	September 11
September 25	October 23	November 6
November 20	December 18	

Next tentative scheduled meeting at NextEra will be on February 17-18, 2016.

Hydro One requested the draft Spring NPCC Workshop Agenda when it is available.

The meeting adjourned at 9:49AM on Thursday, February 19, 2015.

Respectfully Submitted,

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

Northeast Power Coordinating Council, Inc. (NPCC)

Antitrust Compliance Guidelines

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

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

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

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

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

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

NPCC Representatives on NERC Standards Drafting Teams						
Project No.	**Project Title**	**DT Type**	**NPCC Representatives**	**Company**	**Telephone**	**E-mail Address**
2007-02	Operating Personnel Communications Protocols	Standard	Tom Irvine	Hydro One Networks	705-792-3004	tom.irvine@hydroone.com
2007-06.2	Phase 2: System Protection Coordination	Standard	RuiDa Shu Po Bun Ear	NPCC Hydro-Quebec TransEnergie	917-934-7976	rshu@npcc.org ear.po-bun@hydro.qc.c
2007-11	Disturbance Monitoring	Standard	Lee Pedowicz	NPCC	212-840-1070	lpedowicz@npcc.org
2007-17.3	Protection System Maintenance and Testing - Phase 3 (Sudden Pressure Relays)	Standard				
2008-02	Undervoltage Load Shedding	Standard	Charles-Eric Langlois	Hydro-Quebec TransEnergie	514-879-4100	langlois.charles-eric@hydro.qc.ca
2009-03	Emergency Operations	Standard	Connie Lowe	Dominion Resource Services, Inc.	804-819-2917	connie.lowe@dom.com
2010-01	Training (PER)	Standard	Mark Grear	Constellation	410-470-4380	mark.grear@constellation.com
2010-02	FAC Five-Year Review Team	Standard	John Beck	Con Edison	212-460-4244	beckj@coned.com
2010-03	Modeling Data (MOD B)	Standard				
2010-04	Demand Data (MOD C)	Standard	Andrey Oks	NPCC	212-840-1070	aoks@npcc.org
2010-05.1	Protection Systems: Phase 1 (Misoperations)	Standard	Paul Difilippo	Hydro One Networks	647-328-7068	paul.difilippo@hydroone.com
2010-05.2	Special Protection Systems (Phase 2)	Standard	John Ciufo	Hydro One Networks	416-345-5258	john.ciufo@hydroone.com
			Charles-Eric Langlois	Hydro-Quebec TransEnergie	514-879-4100	langlois.charles-eric@hydro.qc.ca
2010-13.3	Phase 3 of Relay Loadability: Stable Power Swings	Standard				
2010-14.1	Balancing Authority Reliability-Based Control, Phase 1: Reserves	Standard	Michael Potishnak	Representing NPCC	413-323-8834	mpot@charter.net
2010-14.2	Balancing Authority Reliability-Based Control, Phase 2	Standard	Michael Potishnak	Representing NPCC	413-323-8834	mpot@charter.net
2010-17	Definition of Bulk Electric System	Standard	Brian Evans-Mongeon	Utility Services	802-552-4022	brian.evans-mongeon@utilitysvcs.com
			Phil Fedora	NPCC	212-840-4909	pfedora@npcc.org
			Ajay Garg	Hydro One Networks	416.345.5420	ajay.garg@HydroOne.com
			Jennifer T. Sterling	Exelon	630-437-2764	jennifer.sterling@exeloncorp.com
2012-09	IRO Five-Year Review	Standard	John Mulhern	Con Edison	212-580-6791	mulhernj@coned.com
2012-13	NUC - Nuclear Plant Interface Coordination	Standard	Kevin Donnelly	Con Edison	914-933-2962	donnellyk@coned.com
2013-03	Geomagnetic Disturbance Mitigation	Standard	Emanuel Bernabeu	Dominion	804-432-8780	emanuel.e.bernabeu@dom.com
			Kenneth Fleischer	NextEra Energy	561-691-2456	kenneth.fleischer@fpl.com
			Luis Marti	Hydro One Networks	416-345-5317	luis.marti@hydroone.com
2013-04	Voltage and Reactive Control (VAR)	Standard	Sharma Kolluri	Entergy	504-576-4045	vkollur@entergy.com
2014-01	Standards Applicability for Dispersed Generation Resources	Standard	Brian Evans-Mongeon	Utility Services	802-552-4022	brian.evans-mongeon@utilitysvcs.com
2014-02	Critical Infrastructure Protection Standards Version 5 Revisions	Standard	Greg Goodrich	NYISO	518-356-7591	ggoodrich@nyiso.com
2014-03	Revisions to TOP/IRO Reliability Standards	Standard				
2014-04	Physical Security	Standard	Kathy Judge	National Grid	508-860-6040	kathleen.judge@nationalgrid.com
2015-02	Emergency Operations Periodic Review	Standard	Connie Lowe	Dominion	804-819-2917	connie.lowe@dom.com
2015-03	Periodic Review of System Operating Limit Standards	Standard	Dean Laforest	ISO-NE		
2015-04	Alignment of NERC Glossary of Terms and Definitions Used in the Rules	Standard	Jill Loewer	Utility Services		
Source = NERC Standard Drafting Team Rosters - May 2014						
Change Control: Changes Since March 2014:						
Projects Removed:			**Projects Added:**			
1. Project 2010-13.2, Phase 2 of Relay Loadability: Generation			1. Project 2014-04, Physical Security			
			2. Project 2015-02 - Emergency Operations Periodic Review			
			3. Project 2015-03 - Periodic Review of System Operating Limit Standards			
			4. Project 2015-04 - Alignment of NERC Glossary of Terms and Definitions Used in the Rules of Procedure (Appendix 2 of the Rules of P			
			5. Project 2007-06.2 - Phase 2: System Protection Coordination			
NPCC Representative Changes:						
1. Project 2010-17, Removed Jennifer Dering as the NPCC Representative as she is no longer at NYPA						
2. Project 2012-13, Added Kevin Donnelly, Con Edison, as the NPCC Representative						
3. Project 2014-03, Added Kyle Russell, IESO, as the NPCC Representative						
4. Project 2014-04, Added Kathy Judge, National Grid, as the NPCC Representative						

Revised: #REF!

Tab Name	Last Revised	Summary of Changes
NERC RS Exec Tracking Summary	4/9/2015	
NERC RSAWs	4/9/2015	
NPCC RRS Tracking Summary	#REF!	- Regional Standard Processes Manual; Following NPCC BOD approval, NERC posted the proposed NPCC Regional Standard Processes Manual for a 45-day industry review through 8 p.m. Eastern on Wednesday, May 7, 2014
NPCC Doc Tracking Summary	#REF!	- C-00 (Discontinued) - C-05 (Retired) - C-07 (Retired) - C-21 (Retired) - C-44 (Retired)
NPCC Directory Tracking Summary	#REF!	- Directory #1, Design and Operation of the Bulk Power System posted in Open Process - Directory Development and Revision Manual - Comment Response Document posted
NPCC Directory Interpretations	#REF!	- Directory #3 Interpretation on behalf of Hydro One Networks included
Quarterly Filing to NSUARB	#REF!	Annotated worksheet to indicate that "Revisions to D#7 and D#12 approved by the Full Members on 7/9/2013. "

Prior Revision

Tab Name	Last Revised	Summary of Changes

NERC Reliability Standards Executive Tracking Summary

Revised: 4/9/2015

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

Acronyms:
SAR- Standards Authorization Request
RS- Reliability Standard
DT- Drafting Team
SC- NERC Standards Committee
TBD- To Be Determined
BOT- NERC Board of Trustee

NERC Reliability Standard Audit Worksheet (RSAW) Executive Tracking Summary

Revised: **4/9/2015**

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

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

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

NPCC Regional Reliability Standards Executive Tracking Summary

Revised: **4/9/2015**

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

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

x

Acronyms:

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

NPCC Document Open Process Executive Tracking Summary

Revised: 4/10/2015

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

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

NPCC Directory Executive Tracking Summary

Revised: 4/10/2015 Further details regarding the individual documents may be found at:

Line No.	Document	Developed From	Title of Directory	Responsible Task Force	Latest Version	Comments	Status
1	Directory #1	Criteria A-2	Design and Operation of the Bulk Power System	TFCP	Dec-09	CP11/CO7 Reviewing Phase 2 Draft	CO7/CP11 developed responses to comments received during the 2nd Open Process comment period and returned the document to TFCO and TFCP with two unresolved issues. TFCO and TFCP approved revised language which defines the scope of the document,thereby resolving one of those issues; however further changes to the Planning and Operations Perf. Requirements have been propsed and TFCO and TFCP have remanded the document back to the CO7/CP11 to consider these proposed revisions. Second major unresolved issues still pending survey to assess economic impact of certain interpretations of the criteria. x
2	Directory #2	Criteria A-3	Emergency Operations	TFCO	Jun-09		
3	Directory #3	Criteria A-4	Maintenance Criteria for Bulk Power System Protection	TFSP	Jun-09		Directory#3 retired effective April 1st, 2015 coinciding with nthe enforcement date of PRC -005-2.
4	Directory #4	Criteria A-5	Bulk Power System Protection Criteria	TFSP	Dec-09	TFSP reviewing D#4 in accordance with NRAP review.	TFSP has completed a periodic review of Directory#4 and the revised document was posted to the Open Prpocess to receive comments through Feb. 2, 2015. TFSP currently reviewing comments.
5	Directory #5	Criteria A-6	Reserve	TFCO	Oct-12		
6	Directory #6		Regional Reserve Sharing		Apr-12		
7	Directory #7	Criteria A-11	Special Protection Systems	TFSP	Jul-13		
8	Directory #8	Criteria A-12	System Restoration	TFCO	Oct-10	TFCO working group CO11 reviewing initial Phase 2 draft of Directory #8.	TFCO will post Directory#8 to the Open Process at the conclusion of the CO-11 review.
9	Directory #9	Criteria A-13	Verification of Generator Gross and Net Real Power Capability	TFCO	Dec-11		TFCO has considered an initial review of the criteria in D#9 and D#10 to insure that it is not inconsistent with MOD-25-2. TFCO agreed to establish a Working Group to consider this issue. (MOD-25-2 is enforceable on 7/1/2016).
10	Directory #10	Criteria A-14	Verification of Generator Gross and Net Reactive Power Capability	TFCO	Dec-11		
11	Directory #12		Under frequency Load Shedding Program Requirements	TFSS	Jul-13		NPCC anticipates retiring Directory#12 once PRC-006-NPCC-1 is fully implemented.
12	Directory Manual		Directory Development and Revision Manual	N/A	Dec-13		On October 6th, 2014 the RSC approved revisions to the Directory Manual which incorporated cost considerations into the development of new or revised criteria as mandated by the NPCC BOD. x

NPCC Directory Criteria Clarifications

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

Line No.	Document	Title of Directory	Date Final	Task Force Review	Posted Open Process?	RCC Approval	Comments	Status
1	Directory #8 Interpretation	System Restoration	6/18/2012	TFCO	N/A	N/A	Interpretation on behalf of the NYSRC	Complete
2	Directory#3 Interpretation	Maintenance Criteria for Bulk Power System Protection	8/28/2012	TFSP	N/A	N/A	Interpretation on behalf of Bangor Hydro	Complete
3	Directory #3 Interpretation	Maintenance Criteria for Bulk Power System Protection	12/14/2012	TFSP	N/A	N/A	Interpretation on behalf of Con Ed	Complete
4	Directory #3 Interpretation	Maintenance Criteria for Bulk Power System Protection	2/15/2013	TFSP	N/A	N/A	Response Clarified - Interpretation on behalf of Acumen Engineered Solutions	Complete
5	Directory#3 Interpretation	Maintenance Criteria for Bulk Power System Protection	10/25/2013	TFSP	N/A	N/A	Interpretation on behalf of Hydro One Networks	Complete
6	Directory#3 Interpretation	Maintenance Criteria for Bulk Power System Protection	3/4/2015	TFSP	Yes on October 16th, 2014.	Yes	Interpretation on behalf of IESO-MACD	Complete.
7	Directory#8 Interpretation	System Restoration	Pending	TFCO	Pending	Pending	Interpretation on behalf of OPG.	Clarification Request forwarded to TFCO on March 23rd, 2015.

x

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

Revised: **4/10/2015**

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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Projected Posting Schedule

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

Week of April 13:

- 2010-04.1 MOD-031 FERC Order No. 804 Directives Standard Authorization Request (SAR) (30-day informal SAR comment period) *(Pending SC authorization on April 15)*

Week of April 20:

- 2008-02.2 Phase 2 of UVLS: Misoperations PRC-004, PRC-010 (Final ballot)
- 2014-04 Physical Security Directives CIP-014 (Final ballot)

Week of April 27:

- 2014-01 Standards Applicability for Dispersed Generation Resources White Paper (30-day informal comment period)

Week of May 4:

- 2015-03 Periodic Review of System Operating Limit Standards FAC-010, FAC-011, FAC-014 (45-day comment period)

Week of May 11:

- None

Week of May 18:

- 2007-06.2 Phase 2 of Protection System PRC-001 (Initial Ballot and 45-day comment period) *(Pending SC authorization May 20)*
- 2007-17.4 PRC-005 FERC Order No. 803 Directive (Initial Ballot and 45-day comment period) *(Pending SC authorization May 20)*
- 2015-06 Interconnection Reliability Operations and Coordination - IRO-006-East, IRO-009 (45-day comment period and initial ballot) *(Pending SC authorization May 20)*

Week of May 25:

- 2010-05.3 Phase 3 of Protection Systems: RAS (Initial Ballot and 45-day comment period) *(Pending SC authorization May 20)*

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

Projects	4/13	4/20	4/27	5/4	5/11	5/18	5/25	Closing Date
2007-06 System Protection Coordination PRC-027					5/15			
2007-06.2 Phase 2 of System Protection Coordination PRC-001						5/21		7/6
2007-17.4 PRC-005 Order No. 803 Directive – SAR						5/22		7/10
2008-02.2 Phase 2 of UVLS: Misoperations PRC-004, PRC-010								
2009-02 Real-time Reliability Monitoring & Analysis Capabilities								
2010-04.1 MOD-031 FERC Order No. 804 Directives Standard SAR	4/16					5/19		
2010-05.3 Phase 3 of Protection Systems: RAS							5/27	7/13
2010-07.1 FAC 003 Vegetation Management								
2010-14.1 Phase 1 of BARC BAL-002								
2010-14.2.1 Phase 2 of BARC BAL-005								
2010-14.2.1 Phase 2 of BARC BAL-006								
2010-14.2.2 Phase 2 of BARC BAL-004 SAR	4/15							
2014-01 Standards Applicability for Dispersed Generation Resources White Paper			4/28					5/27
2014-04 Physical Security Directives CIP-014								
2015-02 Periodic Review of Emergency Operations					5/11			
2015-03 Periodic Review of System Operating Limit Standards FAC-010				5/6				6/18
2015-03 Periodic Review of System Operating Limit Standards FAC-011				5/6				6/18
2015-03 Periodic Review of System Operating Limit Standards FAC-014				5/6				6/18
2015-04 Alignment of NERC Glossary of Terms & Definitions Used in the Rules of Procedures (Appendix 2 of the Rules of Procedures) – SAR	4/13							
2015-06 Interconnection Reliability Operations and Coordination – IRO-006-East, IRO-009 SAR	4/15					5/21		7/8
Number of Standards Posted	6	3	4	7	7	8	8	8

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

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

Item	Description	Owner	Due	Status
4.1	Coordination with the Compliance Committee to develop Joint Activity Action List	Greg Campoli	RSC Meeting	Ongoing Guy Zito provided updates on the RSAWs. CC will review RSAWs going forward.
4.2	NPCC outreach program development – discussion item: members provide input and opportunities for development of an outreach program	RSC	RSC Meeting	Update: Ongoing, two outreaches have been done with NYPA.

DRAFT

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Weekly Standards & Compliance Bulletin

April 13–19, 2015

ACTIVE STANDARDS POSTINGS

Current and Upcoming Ballots (ballot periods close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
Project 2007-06 – System Protection Coordination – PRC-027-1	Ballot in the SBS	05/06/15	05/15/15

Join Ballot Pools (ballot pool windows close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
Project 2007-06 – System Protection Coordination – PRC-027-1	Join Ballot Pool in SBS	04/01/15	04/30/15

Posted for Comment (comment periods close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
Project 2015-04 – Alignment of NERC Glossary of Terms and Definitions Used in the Rules of Procedure – Standard Authorization Request	Comment Form in SBS	03/13/15	04/13/15
Project 2015-06 – Interconnection Reliability Operations and Coordination – Standard Authorization Request	Comment Form in SBS	03/16/15	04/15/15
Project 2010-14.2.2 – Phase 2 of Balancing Authority Reliability-based Controls – Standard Authorization Request	Comment Form in SBS	03/17/15	04/15/15
Project 2015-02 – Periodic Review of Emergency Operations – EOP-004-2, EOP-005-2, EOP-006-2, EOP-008-1	Comment Form in SBS	03/27/15	05/11/15
Project 2007-06 – System Protection Coordination – PRC-027-1	Comment Form in SBS	04/01/15	05/15/15

OTHER ACTIVE COMMENT PERIODS

Posted for Comment			
Posting	**Action**	**Start Date**	**End Date**
CIP V5 RSAWs Posted: Draft RSAWs for Project 2014-02 – Critical Infrastructure Protection Standards Version 5 Revisions have been posted for industry comment. NERC filed the CIP V5 standards with FERC on February 13, 2015, but the Project 2014-02 drafting team requested additional time to collaborate with the NERC CIP RSAW development team to draft the RSAWs after the standard development process concluded. Therefore, the RSAWs are posted for industry comment, but there is no concurrent standards comment period or ballot.	Submit comments to RSAWfeedback@nerc.net.	03/13/15	04/14/15
CIP V5 Transition Program FAQs Posted: NERC has posted a new group of FAQs to the CIP V5 Transition Program web page for industry comment. NERC will review all comments provided and incorporate changes before issuing a final version of the April 1, 2015 FAQs. **NOTE:** NERC initially posted a PDF version of the FAQ document; please disregard that document and use the now-posted Word version to submit comments.	Type comments directly into the draft FAQ document as instructed in the document and submit the feedback to TransitionProgram@nerc.net.	04/01/15	05/15/15
NEW Proposed Revisions to NERC Rules of Procedure Posted for Comment: NERC requests comments on proposed changes to its Rules of Procedure (ROP) Section 400, Appendix 2, and Appendix 4C, as part of the Reliability Assurance Initiative. Redline versions of Sections 401.6, 403.8, and 403.16, and Appendices 2 and 4C are posted on NERC's Rules of Procedure page. A summary document posted on that page provides details about the proposed revisions.	Submit comments to ROPcomments@nerc.net.	04/06/15	05/21/15

GENERAL STANDARDS NEWS

There is no additional standards news to report from last week.

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

GENERAL COMPLIANCE AND ENFORCEMENT NEWS

Risk Elements Monthly Webinar Series Schedule and Registration

As part of its continued outreach efforts in the implementation of its risk-based compliance monitoring and enforcement program (CMEP), the ERO Enterprise will host a series of webinars on each risk element outlined in the 2015 CMEP Implementation Plan. Each monthly webinar will focus on one risk element and include guidance and discussion on the areas of focus identified in the 2015 CMEP Implementation Plan. The webinars will take place on the third Thursday of the month and last no longer than one hour.

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

The ERO Enterprise kicked off this effort by holding the first risk element session on Human Error at the 2015 Spring Standards and Compliance workshop. Register for the other sessions below:

Risk Element	Date
Uncoordinated Protection Systems	April 16, 2015
Monitoring and Situational Awareness	May 21, 2015
Infrastructure Maintenance	June 18, 2015
Protection System Misoperation	July 16, 2015

Workforce Capability	August 20, 2015
Long Term Planning and System Analysis	September 17, 2015
Extreme Physical Events	October 15, 2015
Threats to Cyber Systems	November 19, 2015

All recorded webinars and other material will be posted here after the events.

STANDARDS SUBJECT TO FUTURE ENFORCEMENT

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

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

July 1, 2017	MOD-033-1 – Steady-State and Dynamic System Model Validation

BOARD OF TRUSTEES AND FERC ACTION

NEW Agenda for FERC Open Meeting Posted

The agenda for the April 16, 2015 FERC open meeting is now available. There are four items of interest to the ERO: Agenda Item E-1: Communications Reliability Standards; Agenda Item E-3: Real Power Balancing Control Performance Reliability Standard; Agenda Item E-5: Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance Reliability Standard; and Agenda Item E-6: Disturbance Monitoring and Reporting Requirements Reliability Standard.

UPCOMING EVENTS

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

Workshops and Conferences

- CIP Version 5 Workshop and Small Group Advisory Sessions (SGAS) – April 21–23, 2015, Atlanta, GA (Register to Attend via Webinar)

Webinars

- Risk Elements Monthly Webinar Series: Uncoordinated Protection Systems – 1:00–2:00 p.m. Eastern, April 16, 2015 (Register)
- NEW Review of Lessons Learned Webinar – 1:30–2:30 p.m. Eastern, April 23, 2015 (Register)
- NEW Project 2015-02 – Periodic Review of Emergency Operations Webinar – 1:00–3:00 p.m. Eastern, April 24, 2015 (Register)
- NEW Project 2007-06 – System Protection Coordination Webinar – 2:00–4:00 p.m. Eastern, April 27, 2015 (Register)
- Risk Elements Monthly Webinar Series: Monitoring and Situational Awareness – 1:00–2:00 p.m. Eastern, May 21, 2015 (Register)

Standing Committee Meetings and Conference Calls

- NEW Board of Trustees Conference Call – 12:30–1:30 p.m. Eastern, April 14, 2015 (Agenda Package)
- Standards Committee Conference Call – 1:00–5:00 p.m. Eastern, April 15, 2015 (NEW Agenda)
- Board of Trustees Committees, Member Representative Committee, and Board of Trustees Meetings – May 6–7, 2015, Arlington, VA (Meeting Registration and Hotel Information)

- **NEW** Standards Committee Meeting – 8:00 a.m.–1:00 p.m. Central, June 10, 2015, Dallas (Register to Attend in Person) (Register to Attend via Webinar)

ABOUT THE WEEKLY STANDARDS & COMPLIANCE BULLETIN

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

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

NPCC, Inc.

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

March 6, 2015

Members, Reliability Coordinating Committee
and
Members, Task Force on Coordination of Operation
Members, Task Force on Coordination of Planning
Members, Task Force on Infrastructure Security and Technology
Members, Task Force on System Protection
Members, Task Force on System Studies

Re: Minutes of the December 2, 2014 RCC Meeting

Sir / Madam:

Attached are the minutes of the December 2, 2014 meeting of the NPCC Reliability Coordinating Committee, as approved at the March 4, 2015 RCC meeting.

Sincerely,

Phil Fedora

Philip A. Fedora
Assistant Vice President-Reliability Services

cc: NPCC Staff

NORTHEAST POWER COORDINATING COUNCIL
Reliability Coordinating Committee Minutes
December 2, 2014

Mr. Briggs called the meeting of the Reliability Coordinating Committee (RCC), held at the Halifax Marriott Harbourfront Hotel to order at 10:00 am.

Attendance

Officers of the Reliability Coordinating Committee

Alden Briggs, Chair	New Brunswick Power Corporation
Michael Schiavone, Co-Vice Chair	National Grid USA (via phone)
Brian Evans-Mongeon, Co-Vice Chair	Utility Services, Inc.

Sector 1 - Transmission Owners

Central Hudson Gas & Electric Corp.	(via written proxy)
Central Maine Power Company	David Conroy
Consolidated Edison Company of New York, Inc.	Mike Forte
Hydro-One, Inc.	Tom Irvine
Long Island Power Authority	(proxy to Anie Philip – via phone)
National Grid USA	Michael Schiavone (via phone)
New Brunswick Power Corporation	(proxy to Alden Briggs)
New York Power Authority	(proxy to Randy Crissman)
New York State Electric & Gas Corp.	(proxy to Dave Conroy)
Northeast Utilities	Brad Bentley (via phone)
Nova Scotia Power Incorporated	David Stanford (Alternate)
Rochester Gas & Electric Corporation	(proxy to Dave Conroy)
The United Illuminating Company	Jonathan Appelbaum (Alternate)
Vermont Transco	Hantz Presume

Sector 2 – Reliability Coordinators

Hydro-Québec TransÉnergie	Pierre Paquet
Independent Electricity System Operator	Mark Wilson
ISO-New England, Inc.	Mike Henderson
New Brunswick Power Corporation	Alden Briggs
New York Independent System Operator	Henry Chao

Sector 3 – Transmission Dependent Utilities, Distribution Companies and Load Serving Entities

Hydro-Québec Distribution	Richard Lagrange (via phone)
New York Power Authority	(proxy to Randy Crissman)
Long Island Power Authority	(proxy to Anie Philip – via phone)
Northeast Utilities	(proxy to Brad Bentley)

Sector 4 Generation Owners

Dominion Energy Marking, Inc.	Connie Lowe (Alternate – via phone)
Dynegy, Inc.	Jim Watson (via phone)
Long Island Power Authority	Anie Philip (Alternate – via phone)
New York Power Authority	Randy Crissman
NextEra Energy Resources	(via written proxy)
Northeast Utilities	(proxy to Barry Bruun)
Ontario Power Generation, Inc.	(via written proxy)

Sector 5 – Marketers, Brokers, and Aggregators

Constellation Energy Commodities Group	(via written proxy)
HQ Energy Marketing Inc.	(via written proxy)
HQ Energy Services (US) Inc.	(via written proxy)
Long Island Power Authority	(proxy to Anie Philip– via phone)
New York Power Authority	(proxy to Randy Crissman)
PPLEnergyPlus, LLC	Elizabeth Davis (Alternate – via phone)
Utility Services	Brian Evans-Mongeon

Sector 6 – State and provincial Regulatory and/or Governmental Authorities

New York Power Authority	(proxy to Randy Crissman)
New York State Department of Public Service	Ed Schrom (Alternate – via phone)

Sector 7 – Sub-Regional Reliability Councils, Customers, other Regional Entities and Interested Entities

New York State Reliability Council, LLC	(via written proxy)

NPCC Staff

Sal Buffamante	Assistant Vice President Compliance Audits and Investigations
Gerry Dunbar (via phone)	Manager of Reliability Criteria Requirements
Phil Fedora	Assistant Vice President, Reliability Services
Kristin Halper	Regulatory Attorney
Brian Hogue	Information Systems & Security Management
Stanley Kopman	Assistant Vice President Compliance, Registration & Enforcement
Quoc Le	Manager, System Planning and Protection
Michael Lombardi (via phone)	Manager, System Studies
Jennifer Budd Mattiello	Vice President and Chief Operating Officer
John Mosier, Jr.	Assistant Vice President of System Operations

Scott Neid	Manager, Compliance Program Development
Andrey Oks (via phone)	Manager, Reliability Performance Criteria Assessment
Paul Roman	Manager, Operations Planning
Edward Schwerdt	President and Chief Executive Officer
Rui Da Shu	Engineer, Reliability Standards
Guy Zito	Assistant Vice President of Standards

Guests

Mike Courchesne (via phone)	Chair, CO-12 Working Group
Paul DiFilippo (via phone)	Chair, Task Force on System Protection
Marc Dusseault	Chair, Task Force on Coordination of Planning
Gregory Goodrich	Chair, Task Force on Infrastructure Security & Technology
Dean Latulipe	Chair, SS-38 Working Group
Vincent Morissette	Hydro-Quebec TransEnergie
John Norden	ISO New England
Lou Oberski	Dominion
Fred Plett	MA AG Office
George Wegh	Northeast Utilities
Isen Widjaja (via phone)	Chair, Load Modeling Working Group
Peter Wong	ISO New England

Quorum Statement

Mr. Fedora indicated that a quorum had been achieved, by member attendance, proxy or alternate designation. He also noted having received the following written proxies:

Sector 1 – Transmission Owners
James McCloskey - Central Hudson Gas & Electric Corporation
Sector 4 – Generator Owners
David Ramkalawan – Ontario Power Generation
Allen Schriver – NextEra Energy Resources
Sector 5 – Marketers, Brokers, and Aggregators
Yannick Vennes – HQ Energy Marketing Inc.
Louis Guilbault - HQ Energy Services (US) Inc.
Glen McCartney – Constellation Energy Commodities Group, Inc.
Sector 7 – Sub Regional Reliability Councils, REs, and Others
Roger Clayton – New York State Reliability Council

Antitrust Guidelines for NPCC Meetings

Mr. Fedora reviewed the NPCC Antitrust Guidelines in the Agenda package, and suggested contacting NPCC Inc.'s Assistant Secretary, Andrew Fawbush, at (904) 598-6133 for further information.

President & CEO Report

Mr. Schwerdt reported on the following items:

Events Analysis and the May 25, 2014 Millstone Outage

To put the overall events analysis effort in perspective, NPCC has reviewed so far this year a total of some 79 system events that have been voluntarily submitted to NPCC by Member Systems. The willingness of the NPCC Members to share events information has resulted in the submittal of some 40 Event Reports to NERC, in which seven opportunities for Lessons Learned were identified and approved for industry-wide posting. In addition, certain of these disturbances rise to the level of significance that they are separately presented to the RCC for review and acceptance. You will recall that this past June, the RCC accepted upon the recommendation of its subject matter expert Task Forces, the detailed post-contingency analyses following the July 3, 2013 disturbance in Hydro Québec. The post analysis of the May 25, 2014 outage of the Millstone Station followed a similar technical review path through the applicable Working Groups and Task Forces and will be presented for your acceptance.

Winter Reliability Assessments

The winter of 2013–2014 brought the Northeast the Polar Vortex, several un-named cold snaps, and a renewed appreciation for fuel availability and fuel diversity. That experience gave rise to a special NERC report and numerous regulatory data requests. This year's NPCC Reliability Assessment for Winter 2014-2015 is again an in-depth, independent, technical and probabilistic analysis of the operational readiness of the five operating areas within Northeastern North America. With respect to ISO-New England, the most vulnerable area within NPCC to the impacts of constraints on gas delivery, the report incorporates the effects on an enhanced Winter Reliability Program, and acknowledges the expectations of improved performance based on increased gas-electric communication and coordination, and the implementation of more timely market signals.

Resource Adequacy and Transmission Reviews

International reliability interdependency requires both thorough assessments and interim reviews of each other's resource and transmission plans to verify that mutual reliance is both justified and appropriate, as well as to provide early warning signs of any negative trends. These invaluable activities are conducted by NPCC's Task Forces and Working Groups against the more-stringent, Regionally-specific criteria that are the foundation of Northeastern North American reliability. On today's agenda alone there are two comprehensive resource adequacy reviews, three interim reviews of resource adequacy, one interim transmission review and a Region-wide long range review of resource

adequacy. He stated it is an impressive body of work for which you should all be very proud.

Taken together, all of the reliability activities reviewed highlight the benefits of strong Regional coordination and demonstrates that NPCC has kept its focus on proactively assuring reliability through collaboration, rather than mandating compliance through enforcement.

Chair Report

Meeting Agenda

Mr. Briggs noted that the approval of the Modification of the Niagara 230 kV Generation Rejection Type I SPS has been struck from the Agenda.

The RCC then approved the Agenda.

New England A-10 Extension Request

Mr. Briggs stated, for the record, that New England's request for a six month extension of the time to complete its re-assessment of BPS classification was approved by the NPCC RCC via electronic ballot concluding October 31, 2014. A quorum (two-thirds of 41) was satisfied by the 36 submitted votes.

Nominating Committee Report

Mr. Briggs said that at the last meeting, the RCC formed a Nominating Committee (consisting of Messrs. Garton and Appelbaum) to recommend a candidate (or candidates) for the position of a 2015 Co-Vice Chair for RCC consideration and NPCC Board approval. He reported that the Nominating Committee has recommended Mr. Crissman of the New York Power Authority (NYPA) for the position of RCC Co-Vice Chair. He has indicated his willingness and ability to serve.

2015-2016 RCC Work Plan

Mr. Briggs indicated that the RCC 2015-2016 Work Plan would be considered for approval later in the meeting following RCC approval of the Task Force 2015-2106 Work Plans.

2015 RCC Roster

Mr. Briggs referred the RCC to the 2015 RCC Roster provided in the Agenda package, and asked for any corrections or changes; none were provided.

2015 RCC Meeting Dates& Locations

Mr. Briggs stated the following dates have been confirmed:

- ✓ Wednesday, March 4 – New York Times Square Residence Inn

- ✓ Wednesday, June 3 – New York Times Square Residence Inn
- ✓ Thursday, September 10 – New York Times Square Residence Inn
- ✓ Tuesday, December 1 – Wolf Road Marriot, Albany, New York

Consent Agenda

The Reliability Coordinating Committee approved the following Consent Agenda items (all written proxies in favor, with four abstentions: Sector 4, Generator Owners – David Ramkalawan, Ontario Power Generation, Inc., Sector 5, Marketers, Brokers, and Aggregators - Glen McCartney, Constellation Energy Commodities Group, Inc., Louis Guilbault, HQ Energy Services (US) Inc., and Yannick Vennes, HQ Energy Marketing Inc.):

September 10, 2014 Meeting Minutes

The Draft-For-Approval Minutes of the September 10, 2014 Reliability Coordinating Committee were approved, with corrections noted.

2015 RCC Co-Vice Chair

The RCC recommends Board approval of Mr. Crissman of the New York Power Authority (NYPA) for the position of RCC Co-Vice Chair.

RCC Membership Changes

The following changes to RCC Membership were approved:

Sector 3, TDUs, Dist. and LSE

- ✓ Mr. Barry Bruun to succeed Mr. Dwayne Basler as member, both of Northeast Utilities.

Sector 4, Generator Owners

- ✓ Mr. Glenroy (Glen) Smith to succeed Mr. Raey Yohanne as member, both of Entergy Nuclear Northeast.
- ✓ Ms. Connie Lowe of Dominion Resources Services, Inc. to succeed Mr. Mike Garton as a member.
- ✓ Mr. Lou Oberski to succeed Ms. Connie Lowe as alternate, both of Dominion Resources Services, Inc.

Sector 5, Marketers, Brokers, Aggregators

- ✓ Mr. Brian Robinson of Utility Services, Inc. to succeed Mr. John Helme as alternate.

Task Force Roster Changes

The following changes to Task Force and Working Group memberships were approved:

Task Force on System Studies

- ✓ Mr. Vitaly Spitsa of Consolidated Edison Company of New York, Inc. to replace Mr. Francesco Elmi of Northeast Power Coordinating Council, Inc. as member.
- ✓ Mr. Martin Paszek to replace Mr. Vitaly Spitsa as alternate, both of Consolidated Edison Company of New York, Inc.
- ✓ Mr. Benoît Delourme of Hydro-Quebec TransÉnergie to serve as an alternate.

SS-37 Working Group on Base Case Development

- ✓ Mr. François Bélanger to replace Mr. Vito DeLuca as member, both of Hydro-Québec TransÉnergie.
- ✓ Khin Swe of New York Power Authority moved from member to observer
- ✓ Mr. Vito DeLuca to replace Jonathan Beaudoin as alternate, both of Hydro-Québec TransÉnergie
- ✓ Mr. Patrick Masterson of New Brunswick Power Corporation to serve as the second Alternate.

Task Force of Infrastructure Security and Technology

- ✓ Mr. Brian O'Boyle of Consolidated Edison Company of New York, Inc. to serve as alternate.
- ✓ Mr. David Cadregari of New York State Electric & Gas Corp. to serve as member.
- ✓ Mr. Scott Dunwoody of Orange and Rockland Utilities, Inc. to serve as an alternate.
- ✓ Mr. Ellen Simpson of Orange and Rockland Utilities, Inc. to serve as member.
- ✓ Mr. John Allen of Rochester Gas & Electric Corp. to serve as an alternate.
- ✓ Mr. Jonathan Appelbaum of The United Illuminating Company as an alternate.
- ✓ Mr. Eric Smith to replace Mr. Brian Evans-Mongeon as an alternate, both of Utility Services, Inc.
- ✓ Mr. Jonathan Appelbaum of The United Illuminating Company succeeds Mr. Greg Goodrich of New York Independent System Operator as Chairman.

2014 Interim Reviews of Resource Adequacy

The *Ontario, New York and Maritimes 2014 Interim Reviews of Resource Adequacy* were approved as provided in the Agenda package.

Ontario Interim Transmission Review

Approved as referenced in the Agenda package.

NPCC representatives to NERC's Critical Infrastructure Protection Committee

Approved as provided in the Agenda package.

Reliability Coordinating Committee Actions

2014 – 2015 NPCC Winter Reliability Assessment

Mr. Courchesne presented the *2014 – 2015 NPCC Winter Reliability Assessment* provided in the Agenda package. The assessment was prepared by the NPCC CO-12 Seasonal Assessment Working Group and focuses on the assessment of reliability within NPCC for the 2014/2015 Winter Operating Period.

Mr. Fedora explained that the NPCC CP-8 Working Group's multi-area probabilistic reliability assessment for the 2014/2015 Winter period was previously approved by the RCC at its June 2014 meeting. Results of CP-8 Working Groups assessment are included as a chapter in this report and supporting documentation is provided in Appendix VIII.

He provided an update of weather outlook based on the latest available US NOAA and Environment Canada Winter forecasts.

The RCC then approved the *2014 – 2015 NPCC Winter Reliability Assessment,* as provided in the Agenda (all written proxies in favor, with four abstentions: Sector 4, Generator Owners – David Ramkalawan, Ontario Power Generation, Inc., Sector 5, Marketers, Brokers, and Aggregators - Louis Guilbault, HQ Energy Services (US) Inc., Yannick Vennes, HQ Energy Marketing Inc., and Glen McCartney, Constellation Energy Commodities Group, Inc.).

New England Comprehensive Review of Resource Adequacy

Mr. Wong summarized the materials provided in the Agenda package related to *the New England Comprehensive Review of Resource Adequacy.* This Review, covering 2015 through 2019, was prepared by ISO-New England accordance with Appendix D of NPCC Directory No. 1 - Guidelines for Area Review of Resource Adequacy.

The TFCP reviewed the report and agrees with its conclusion that the New England Area will comply with the NPCC Resource Adequacy Criterion for all years from 2015 to 2019 and recommends RCC approval.

The RCC approved the *New England Comprehensive Review of Resource Adequacy* as provided in the Agenda package (all written proxies in favor, with four abstentions: Sector 4, Generator Owners – David Ramkalawan, Ontario Power Generation, Inc., Sector 5, Marketers, Brokers, and Aggregators – Louis Guilbault, HQ Energy Services (US) Inc., Yannick Vennes, HQ Energy Marketing Inc., and Glen McCartney, Constellation Energy Commodities Group, Inc.).

Quebec Comprehensive Review of Resource Adequacy

Mr. Lagrange summarized the materials provided in the Agenda package related to the *Quebec Comprehensive Review of Resource Adequacy.* The Review (submitted in accordance with Appendix D of NPCC Directory No. 1 - Guidelines for Area Review of Resource Adequacy) covers the study period from winter 2014-2015 through winter 2018-2019. Changes in assumptions about facility and system conditions, generation resources availability, load forecast and electricity sector regulations since the last Comprehensive Review and the impact of these changes on the overall reliability of the Québec electricity system were described.

The TFCP reviewed the report and agrees with its conclusion that the Quebec Area will comply with the NPCC Resource Adequacy criteria for all years from 2015 to 2019 and recommends RCC approval.

The RCC then approved the *Quebec Comprehensive Review of Resource Adequacy*, as provided in the Agenda package (all written proxies in favor, with three abstentions: Sector 4, Generator Owners – David Ramkalawan, Ontario Power Generation, Inc., Sector 5, Marketers, Brokers, and Aggregators – Louis Guilbault, HQ Energy Services (US) Inc., and Yannick Vennes, HQ Energy Marketing Inc.).

NPCC 2014 Long Range Adequacy Overview

Mr. Fedora explained that the *NPCC 2014 Long Range Adequacy Overview* evaluated, on a consistent basis, the long range adequacy of NPCC and neighboring Regions' plans to meet their Resource Adequacy Planning Criteria through a multi-area probabilistic assessment for the period from 2015 to 2019, based on the information reported in *NERC 2014 Long Term Reliability Assessment* and the respective *NPCC Area Reviews of Resource Adequacy*. The study demonstrated that the NPCC areas are estimated to have, on average, an annual LOLE less than 0.1 days/year through the 2015 – 2019 study period.

The Task Force on Coordination of Planning reviewed the report, agreed with the report's assessment and recommends RCC approval.

The RCC then approved the *NPCC 2014 Long Range Adequacy Overview*, as provided in the Agenda package (all written proxies in favor, with three abstentions: Sector 4, Generator Owners – David Ramkalawan, Ontario Power Generation, Inc., Sector 5, Marketers, Brokers, and Aggregators – Louis Guilbault, HQ Energy Services (US) Inc., and Yannick Vennes, HQ Energy Marketing Inc.).

SPS retirements/modifications associated with the Maine Power Reliability Program (MPRP)

In accordance with the NPCC Regional Reliability Reference Directory No 7 - Special Protection Systems Appendix B, Section 3, Mr. Conroy notified the RCC of Central Maine's Power intent to retire two Type I and two Type III SPSs, and remove Maine inputs the Maritimes Islanding Type I SPS. He explained as a result of the system reinforcements accomplished by having the MPRP in-service, there will no longer be a need for these SPSs.

The Task Force on System Studies and Task Force on Coordination of Planning have both reviewed the request, and recommends approval of the proposed SPS retirements/modifications associated with the MPRP, according to the stated schedules.

The RCC then approved the SPS retirements/modifications associated with the Maine Power Reliability Program, according to the stated schedules, as provided in

the Agenda package (all written proxies in favor, with three abstentions: Sector 4, Generator Owners – David Ramkalawan, Ontario Power Generation, Inc., Sector 5, Marketers, Brokers, and Aggregators – Louis Guilbault, HQ Energy Services (US) Inc., and Yannick Vennes, HQ Energy Marketing Inc.).

UFLS Adequacy Assessment

Messrs. Latulipe and Morissette presented the SS-38 Working Group's NPCC *UFLS Adequacy Assessment for the year 2018*. The assessment, provided in the Agenda package, was reviewed with TFSS and is recommended for RCC approval.

The RCC agreed with the report's conclusion that the IESO, New Brunswick, the New York-ISO, ISO-New England and Hydro-Quebec UFLS programs implemented in their respective areas are in conformance with the NPCC Directory No. 12 UFLS Implementation Plan, and are coordinated and meet the performance characteristics in simulations of underfrequency conditions defined in NERC PRC-006-1 standard, for the NPCC system topology expected in 2018.

The RCC then approved the *UFLS Adequacy Assessment for the year 2018*, as provided in the Agenda package (all written proxies in favor, with three abstentions: Sector 4, Generator Owners – David Ramkalawan, Ontario Power Generation, Inc., Sector 5, Marketers, Brokers, and Aggregators – Louis Guilbault, HQ Energy Services (US) Inc., and Yannick Vennes, HQ Energy Marketing Inc.).

2015 NPCC Criteria Compliance Enforcement Program Implementation Plan

Mr. Kopman presented the *2015 NPCC Criteria Compliance Enforcement Program Implementation Plan* provided in the Agenda package.

The RCC reviewed and approved the *CCEP Implementation Plan* recommended by NPCC Compliance Committee for the NPCC Criteria (i.e., NPCC Directories) that will be actively monitored for the specified CCEP compliance years. The Implementation Plan specifies the due dates, compliance years, and the reporting and certifying entities for each submittal. Full Members will be required to Self-Report compliance with these Criteria/Directories.

The RCC then approved *2015 NPCC Criteria Compliance Enforcement Program Implementation Plan*, as provided in the Agenda package (all written proxies in favor, with three abstentions: Sector 4, Generator Owners – David Ramkalawan, Ontario Power Generation, Inc., Sector 5, Marketers, Brokers, and Aggregators – Louis Guilbault, HQ Energy Services (US) Inc., and Yannick Vennes, HQ Energy Marketing Inc.).

2015-2016 Task Force Work Plans

The Task Force chairs highlighted their respective 2015-2016 Task Force Work Plans provided in the Agenda Package.

The RCC then approved the 2015-2016 Task Force Work Plans, as provided in the Agenda package (all written proxies in favor, with three abstentions: Sector 4, Generator Owners – David Ramkalawan, Ontario Power Generation, Inc., Sector 5, Marketers, Brokers, and Aggregators – Louis Guilbault, HQ Energy Services (US) Inc., and Yannick Vennes, HQ Energy Marketing Inc.).

2015-2016 RCC Work Plan

Following review and approval of the NPCC Task Forces' respective 2015-2016 Work Plans, the RCC reviewed its 2015-2016 Work Plan.

The RCC then approved the 2015-2016 RCC Work Plan, as provided in the Agenda package (all written proxies in favor, with three abstentions: Sector 4, Generator Owners – David Ramkalawan, Ontario Power Generation, Inc., Sector 5, Marketers, Brokers, and Aggregators – Louis Guilbault, HQ Energy Services (US) Inc., and Yannick Vennes, HQ Energy Marketing Inc.).

Millstone Event Analysis

Messrs. Bruun and Wegh described a May 25, 2014, event during which off-site power to the Millstone nuclear station was interrupted, and presented Northeast Utilities' findings and causal analysis identifying the root and contributing factors of the disturbance, together with the mitigating actions pursued by Northeast Utilities. NPCC's Task Force on the Coordination of Operation, the Task Force on the Coordination of Planning, and the Task Force on System Protection presented their respective reviews of the event analysis.

The RCC accepted the analysis presented by Northeast Utilities, including the corresponding respective NPCC Task reviews of the analysis. The Task Force on Coordination of Operation agreed to monitor the status to completion of the implementation of the recommendations of the report**.**

Status Reports

Mr. Briggs referred the RCC to the materials provided in the Agenda package; the RCC discussed the following Agenda items:

NPCC Regional Standards Committee (RSC) Report

Mr. Zito briefly explained that he has been working with Mr. DiFilippo, TFSP Chair, regarding a strategy moving forward regarding the PRC-005 Standard, and reminded the RCC that the PRC-002-NPCC-01 Standard was developed from the NPCC A15 criteria, which is still in place. He also emphasized the NPCC Board's interest cost effectiveness being applied to both the NPCC Regional Standards and the NPCC criteria.

NPCC Compliance Committee

Mr. Buffamante reported that 1) the RAI dominated the extra Audit area activities in 2014; every audit conducted in 2015 followed the Inherent Risk Assessment for the Entity, 2) Internal controls evaluation will commence in 2015 for Entities that agree, and 3) the Self-certification program is under review with respect to alignment with the concepts of RAI.

Regarding enforcement area activities, Mr. Kopman then made the following points:

- ✓ The number of possible violations have been reduced, from a high of 264 possible violations (identified in 2012) , to 62 (through October 2014). The reduction is due primarily to NPCC outreach efforts, workshops, webinars and the Registered Entities work to improve their compliance programs and internal compliance procedures.
- ✓ The average time to process violations (from discovery until released to NERC) has been reduced, from an average of ~339 days (at the end of 2013) to an average of 110 days (through October 2014), due primarily to the reduction of the number of violations being reported, and the new process and procedures related to the RAI.

Phase 2 Revision of Directory No. 1

Mr. Briggs noted that the Phase 2 revision of Directory No. 1 was expected to be presented to the RCC at this meeting. Mr. Norden explained that the Task Force on Coordination of Operation and the Task Force on Coordination of Planning are working to resolve two remaining issues by the first quarter of 2015; with the exception of the identified issues, the revision is approximately 98% complete.

CIP Version 5 Revisions Update

Mr. Goodrich noted a recent revision to the CIP Version 5 schedule; balloting will be open from November 25, 2014 through January 8, 2015; with a final ballot period from January 16 through January 26, 2015.

With respect to the Physical Security Standard (CIP-014-1) he updated the RCC that the Commission will not modify CIP-014-1 to allow governmental entities to add or subtract facilities proposed by FERC. "We determine that the Commission's enforcement authority under FPA Section 215(e), and particularly the use of targeted auditing following implementation of Reliability Standard CIP-014-1, will allow us to address the concerns raised in the NOPR."

NERC Agenda Items

Operating Committee (OC)

Mr. Mosier reviewed the following December 2014 NERC Operating Committee Agenda items:

- ✓ Approval of the Standards Committee Guideline: Approving a Field Test Associated with a reliability Standard;
- ✓ Approval of a new Reliability Guideline: Generating Unit Operations During Complete Loss of Communications;
- ✓ Eastern Interconnection Frequency Response Initiative; and,
- ✓ Approval of the Integration of Variable Generation Task Force Final Summary Report and Recommendations.

Planning Committee (PC)

Mr. Fedora reviewed the following items from the Draft December 2014 NERC Planning Committee Agenda:

- ✓ TADSWG recommendation of the sunset of collection of planned outage data;
- ✓ Approval of the Integration of Variable Generation Task Force Final Summary Report and Recommendations; and,
- ✓ AC Substation Equipment Task Force Report and Recommendations.

Mr. Evans-Mongeon then provided an update on the NERC Essential Reliability Services Task Force activities. He explained to keep the initiative on schedule, the "*Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability*" will be presented to the PC for their endorsement.

Critical Infrastructure Protection Committee (CIPC)

Mr. Hogue reviewed the following items on the December 2014 NERC Critical Infrastructure Committee Agenda:

- ✓ CIP version 5 revisions;
- ✓ CIP version 3 transition to CIP version 5 and,
- ✓ CIP-014 – Physical Security Standard – the mandatory compliance date is October 1, 2015.

Informational Items

Mr. Briggs referred the RCC to the materials included in the Agenda package. The following Informational Items were discussed at the meeting:

GridEx III

Mr. Goodrich explained that GridEx III is scheduled for November 18 – 19, 2015. NERC is encouraging Operating Committee participation, asking Reliability Coordinators to take more a role during the exercise. Entity Operations, Information

Technologies, Cyber Security, Physical Security and Business Continuity and Resiliency staffs are also being asked to consider participating in GridEx III.

NPCC Frequency Response Activities

Mr. Roman briefly summarized the materials provided in the Agenda package regarding recent NPCC Frequency Response activities. He explained that NPCC staff and a consultant have been working over the last five to six months with the NPCC Balancing Authorities to complete a governor response survey in order to obtain accurate generator response information for modeling improvement of the governor representation used for dynamic simulation of Eastern Interconnection Frequency Response. The frequency response of NPCC generators >100 MW will be compared against actual system frequency response performance for many events, in order to improve the coordination of governor and plant controls settings.

Other Matters

On behalf of the RCC, Mr. Fedora thanked Mr. Briggs for his leadership as the RCC Chair, and acknowledged his commitment and contributions during his involvement with the RCC. Mr. Briggs responded that it has been an honor and a privilege serving as RCC Chair, and thanked the NPCC staff, Task Forces and Working Groups for their many efforts.

With no other matters to consider, the RCC meeting was adjourned.

Next RCC Meeting Date	**Location**
March 4, 2015	Marriott New York Times Square Residence Inn

Distribution of Approved Minutes

NPCC Full & General Member Representatives and Alternates
Members, NPCC Board of Directors
Members, NPCC Reliability Coordinating Committee
Members, NPCC Public Information Committee
Members, NPCC Compliance Committee
Members, NPCC Regional Standards Committee
Members, NPCC Task Force on Coordination of Operation
Members, NPCC Task Force on Coordination of Planning
Members, NPCC Task Force on Infrastructure Security and Technology
Members, NPCC Task Force on System Protection
Members, NPCC Task Force on System Studies
NPCC Officers
NPCC Staff
Ruta Skucas, Esq.

and
Federal Energy Regulatory Commission – Mike Bardee, David O'Connor, Juan Villar
La Régie de L'Énergie – Daniel Soulier
Ontario Energy Board – Peter Fraser
United States Department of Energy – David Meyer
New Brunswick Department of Energy and Mines – David Sallows
Nova Scotia Utility & Review Board – S. Bruce Outhouse, Q.C.

PRO FORMA
REGIONAL DELEGATION AGREEMENT
DATED [•]

(*accepted [•]*)

AMENDED AND RESTATED DELEGATION AGREEMENT BETWEEN NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION AND [REGIONAL ENTITY]

AMENDED AND RESTATED DELEGATION AGREEMENT ("Agreement") ~~made~~ Effective as of January 1, ~~2011~~2016, between the North American Electric Reliability Corporation ("NERC"), an organization certified by the Federal Energy Regulatory Commission ("Commission") pursuant to Section 215(c) of the Federal Power Act to establish and enforce Reliability Standards for the Bulk-Power System, and [REGIONAL ENTITY], an organization established to develop and enforce Reliability Standards within the geographic boundaries identified on **Exhibit A** to this Agreement, and for other purposes. NERC and [REGIONAL ENTITY] may be individually referred to herein as "Party" or collectively as "Parties."

WITNESSETH

WHEREAS, Subtitle A of the Electricity Modernization Act of 2005 added Section 215 to the Federal Power Act (16 U.S.C. § 824n) (hereafter "the Act"), which, among other things, provides for the establishment of an ~~electric reliability organization~~Electric Reliability Organization ("ERO") to develop and enforce Reliability Standards applicable to all owners, operators, and users of the Bulk-Power System;

WHEREAS, the Commission has adopted regulations for the implementation of the Act, which are set forth at Chapter I, Title 18, Code of Federal Regulations, Part 39 (the "ERO Regulations");

WHEREAS, the Commission has certified NERC as the ERO that will, in accordance with the Act, establish and enforce Reliability Standards for the Bulk-Power System, subject to certain delegation provisions described below;

WHEREAS, the Act recognizes the international interdependency of electric reliability within North America and envisions the ERO and such applicable Regional Entities as international organizations;

WHEREAS, the Act and Section 39.8 of the ERO Regulations provide for the delegation by the ERO of authority to propose and enforce Reliability Standards to regional entities ("Regional Entities") such as [REGIONAL ENTITY~~]~~], provided that:

(A) The Regional Entity is governed by —

(i) an independent board;

(ii) a balanced stakeholder board; or

(iii) a combination independent and balanced stakeholder board.

(B) The Regional Entity otherwise satisfies the provisions of Section 215(c)(1) and (2) of the Act; and

(C) The agreement promotes effective and efficient administration of Bulk-Power System reliability;

WHEREAS, certain Regional Entities are organized on an Interconnection-wide basis and are therefore entitled to the presumption set forth in the Act that: "[t]he ERO and the Commission shall rebuttably presume that a proposal for delegation to a Regional Entity organized on an Interconnection-wide basis promotes effective and efficient administration of bulk power system reliability and should be approved";

WHEREAS, the Act further provides that the ERO shall rebuttably presume that a proposal from a Regional Entity organized on an Interconnection-wide basis for a Reliability Standard or modification to a Reliability Standard to be applicable on an Interconnection-wide basis is just, reasonable, and not unduly discriminatory or preferential, and in the public interest;

WHEREAS, [REGIONAL ENTITY] [is/is not] organized on an Interconnection-wide basis and therefore [is/is not] entitled to the rebuttable presumptions accorded such an entity;

WHEREAS, NERC will work through [REGIONAL ENTITY] to carry out certain of its activities in furtherance of its responsibilities as the ERO under the Act;

WHEREAS, NERC has concluded that [REGIONAL ENTITY] meets all requirements of the Act, the ERO Regulations, and the NERC Rules of Procedure as approved by the Commission ("NERC Rules of Procedure") necessary to qualify for delegation; and

WHEREAS, NERC and [REGIONAL ENTITY], having operated under a predecessor agreement to this Agreement, have negotiated this amended and restated Agreement so as to incorporate the benefits of their mutual experience and lessons learned while operating under the predecessor agreement and thereby provide for the more efficient and effective execution of their respective responsibilities in a transparent manner that is pursuant to Section 215 of the Act and the ERO Regulations;

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein contained, NERC and [REGIONAL ENTITY] agree as follows:

1. Definitions. The capitalized terms used in this Agreement shall be defined as set forth in the Act, the ERO Regulations, the NERC Rules of Procedure, or the NERC Glossary of Terms Used in Reliability Standards, or, if not so defined, shall be defined as set forth in this Section 1 or elsewhere in the text of this Agreement:

(a) Breach means (i) the failure of a Party to perform or observe any material term, condition or covenant of the Agreement or (ii) a representation in Section 2 of the Agreement shall have become materially untrue.

(b) Cross-Border Regional Entity means a Regional Entity that encompasses a part of the United States and a part of Canada or Mexico.

(c) Delegated Authority means the authority delegated by NERC to [REGIONAL ENTITY] to propose and enforce Reliability Standards, consistent with Section 4(d), within the boundaries identified on **Exhibit A** pursuant to the Act and to undertake related activities set forth in this Agreement in furtherance of these delegated functions in accordance with the Act, the ERO Regulations and this Agreement.

2. Representations.

(a) For purposes of its Delegated Authority, [REGIONAL ENTITY] hereby represents and warrants to NERC that:

(i) [REGIONAL ENTITY] is and shall remain during the term of this Agreement validly existing and in good standing pursuant to all applicable laws relevant to this Agreement and that no applicable law, contract or other legal obligation prevents it from executing this Agreement and fulfilling its obligations hereunder. [REGIONAL ENTITY] is governed in accordance with its bylaws by [select appropriate: an independent board/a balanced stakeholder board/ a combination independent and balanced stakeholder board]. Pursuant to these bylaws, no two industry sectors can control any [REGIONAL ENTITY] decision and no single industry sector can veto any [REGIONAL ENTITY] decision. ~~The relevant portions of~~The relevant criteria for the establishment of such bylaws are attached hereto in Exhibit B. No other [REGIONAL ENTITY] corporate governance documents shall be inconsistent with the criteria in Exhibit B.

~~such bylaws are attached hereto in **Exhibit B**[1], and as so attached are in full force and effect. No other such corporate governance documents are binding upon [REGIONAL ENTITY].~~

~~As set forth in **Exhibit C** hereto[2];~~

(ii) [REGIONAL ENTITY] has developed a standards development procedure, which provides the process that [REGIONAL ENTITY] may use to develop Regional Reliability Standards [and Regional Variances, if the regional entity is organized on an Interconnection-wide basis] that are proposed to NERC for adoption.

(iii) As set forth in **Exhibit D** hereto, [REGIONAL ENTITY] has adopted the NERC Compliance Monitoring and Enforcement Program, Appendix 4C to the NERC Rules of Procedure, which provides for the enforcement of Reliability Standards within [REGIONAL ENTITY]'s geographic boundaries as shown on **Exhibit A**.

(b) NERC hereby represents and warrants to [REGIONAL ENTITY] that:

(i) NERC is and shall remain during the term of this Agreement validly existing and in good standing pursuant to all applicable laws relevant to this Agreement and that no applicable law, contract or other legal obligation prevents it from executing this Agreement and fulfilling its obligations hereunder; and

(ii) NERC has been certified as the ERO by the Commission pursuant to the Act.

[1] ~~The **Exhibit B** from [REGIONAL ENTITY] shall meet the requirements contained in **Exhibit B** to this Agreement.~~

[2] ~~The **Exhibit C** from [REGIONAL ENTITY] shall meet the requirements contained in **Exhibit C** to this Agreement.~~

(iii) NERC shall comply with its Certificate of Incorporation, Bylaws and Rules of Procedure, as from time to time adopted, approved or amended.

3. Covenants.

(a) During the term of this Agreement, [REGIONAL ENTITY] shall maintain and preserve its qualifications for delegation pursuant to the Act and shall not amend its Regional Entity Rules without NERC approval, which shall not be unreasonably withheld or delayed and which shall, in the case of a Regional Entity organized on an Interconnectionwide basis, be governed by the presumptions provided for in Section 215(d)(2) and (e)(4)(C) of the Act, and be subject to any required Commission approval.

(b) [REGIONAL ENTITY] shall provide NERC with a copy of its Regional Entity Rules upon request by NERC.

~~(b)~~(c) During the term of this Agreement, NERC shall maintain its qualification and status as the ERO pursuant to the Act and, subject to the provisions of Sections 17 and 18 of this Agreement, NERC shall not adopt amendments to the NERC Rules of Procedure that conflict with the rights, obligations or programs of [REGIONAL ENTITY] under this Agreement without first obtaining the consent of [REGIONAL ENTITY], which consent shall not be unreasonably withheld or delayed.

~~(c)~~(d) During the term of this Agreement, NERC and [REGIONAL ENTITY] shall adhere to and require that all participants in their respective activities under this Agreement follow and comply with the NERC Antitrust Compliance Guidelines.

4. Delegation of Authority.

~~(a)~~ Based upon the representations, warranties and covenants of [REGIONAL ENTITY] in ~~Sections 2 and 3 above, the~~ this Agreement, [REGIONAL ENTITY's] corporate governance documents ~~set forth in **Exhibit B**~~, the [REGIONAL ENTITY's] standards development process ~~set forth in **Exhibit C**~~, and the compliance monitoring and enforcement program set forth in **Exhibit D**, NERC hereby delegates authority, pursuant to Section 215(e)(4) of the Act, to [REGIONAL ENTITY] for the purpose of proposing Reliability Standards to NERC, as set forth in Section 5 of this Agreement, and enforcing Reliability Standards, as set forth in Section 6 of this Agreement, within the geographic boundaries and

such other scope set forth on **Exhibit A**, *provided*, that [REGIONAL ENTITY] shall not monitor and enforce compliance with Reliability Standards for [REGIONAL ENTITY] or an affiliated entity with respect to reliability functions for which [REGIONAL ENTITY] or an affiliate is a Registered Entity. Any exclusions from this delegation of authority to

~~(b)~~(a) [REGIONAL ENTITY] within, or additions to this delegation of authority to [REGIONAL ENTITY] beyond, the geographic boundaries set forth ~~on~~in **Exhibit A** are stated ~~on~~in **Exhibit A**.

~~(c)~~(b) In circumstances where [REGIONAL ENTITY] or an affiliated entity is a Registered Entity, [REGIONAL ENTITY] shall enter into an agreement with another Regional Entity or NERC for the other Regional Entity or NERC to monitor and enforce [REGIONAL ENTITY]'s or affiliate's compliance with Reliability Standards. ~~-~~Such agreements are subject to NERC and Commission approval.

~~(d)~~(c) Nothing in this Agreement~~-~~ shall prohibit [REGIONAL ENTITY] from entering into an arrangement between one or more other Regional Entities to perform compliance monitoring and enforcement activities outside of its region, on behalf of NERC and/or other Regional Entities, for Registered Entities that have registered functions monitored by more than one Regional Entity, subject to approval by NERC.

~~(e)~~(d) For Cross-Border Regional Entities, the authority delegated by this Agreement shall extend only to the portion of the region identified on **Exhibit A** that is within the United States. Any delegation of authority by ~~ERO~~Applicable Governmental Authorities in Canada or Mexico shall be governed by the law of such authority or a separate agreement and is outside the scope of this Agreement; provided, however, that both [REGIONAL ENTITY] and NERC shall endeavor to ensure that this Agreement and any such separate ~~agreements~~agreement are compatible.

(e) As a condition to this delegation of authority and subject to the provisions of Section 17 of this Agreement, [REGIONAL ENTITY] shall comply with the applicable provisions of NERC's ~~Certificate of Incorporation, Bylaws,~~ Rules of Procedure, ~~and Reliability Standards,~~ as from time to time adopted, approved, or amended.

5. Development and Proposal of Reliability Standards.

(a) In connection with its Delegated Authority, [REGIONAL ENTITY] shall be entitled to:

(i) propose Reliability Standards, Regional Variances, or modifications thereof to NERC, which shall be considered by NERC through an open and inclusive process

for proposing and adopting Reliability Standards that affords [REGIONAL ENTITY] reasonable notice and opportunity to be heard; and

(ii) develop Regional Reliability Standards [and Regional Variances, if Regional Entity is organized on an Interconnection-wide basis] through [REGIONAL ENTITY]'s process ~~as set forth in **Exhibit C**~~. [REGIONAL ENTITY]'s process shall be consistent with the NERC Rules of Procedure and Commission directives. Any changes to [REGIONAL ENTITY]'s process shall be submitted to the NERC Board of Trustees for approval and upon approval, be submitted to the Commission for approval. Proposals approved through [REGIONAL ENTITY]'s process shall be reviewed by the NERC Board of Trustees after NERC provides notice and an opportunity for interested persons to comment. In the case of a proposal from a Regional Entity organized on an Interconnection-wide basis, comments shall be limited to the factors identified in NERC Rule of Procedure 312.3 as it may be amended from time to time. The NERC Board of Trustees shall promptly thereafter consider such proposed Regional Reliability Standard or Regional Variance, applying the rebuttable presumption described in subsection 5(b) of this Agreement if the proposed Regional Reliability Standard or Regional Variance is from a Regional Entity organized on an Interconnection-wide basis, and either approve the proposed Regional Reliability Standard or Regional Variance and submit it to the Commission for approval, or disapprove it in writing setting forth its reasons. [REGIONAL ENTITY] may appeal any disapproval of a proposed Regional Reliability Standard or Regional Variance to the Commission.

(b) Pursuant to Section 215(d)(3) of the Act, NERC shall rebuttably presume that a proposal from a Regional Entity organized on an Interconnection-wide basis for a Regional Reliability Standard or Regional Variance or modification thereof to be applicable on an Interconnection-wide basis is just, reasonable, and not unduly discriminatory or preferential, and in the public interest. Any person challenging such proposal from the Regional Entity organized on an Interconnection-wide basis shall have the burden of proof. NERC shall not find that this presumption has been rebutted except based upon substantial evidence that has been disclosed to, and been subject to comment by, the Interconnection-wide Regional Entity during NERC's review of the proposal.

6. Enforcement of Compliance with Reliability Standards.

~~(a)~~ In connection with its delegated authority pursuant to this Agreement, [REGIONAL ENTITY] shall enforce Reliability Standards (including Regional Reliability Standards and Regional Variances) within the ~~geographic~~ boundaries set forth~~, or as otherwise~~

~~specified,~~ in **Exhibit A** through the compliance monitoring and enforcement program set forth in **Exhibit D**. NERC and [REGIONAL ENTITY] agree that this compliance monitoring and

~~(b)~~(a) enforcement program meets all applicable requirements of the Act, Order No. 672 of the Commission, and the ERO Regulations, including, inter alia, the requirement for an audit program pursuant to Section 39.7(a) of the ERO Regulations, the assessment of penalties pursuant to Section 39.7(c) through 39.7(g) of the ERO Regulations and the requirements for due process. [REGIONAL ENTITY] may not change its compliance monitoring and enforcement program set forth in **Exhibit D** absent NERC's approval, which shall not be unreasonably withheld or delayed, and the approval of the Commission. Subject to the rights and limitations specified in Sections 17 and 18 of this Agreement, [REGIONAL ENTITY] agrees to comply with the NERC Rules of Procedure, with any directives issued pursuant to Section 8(c) of this Agreement, and with any guidance and directions issued by the NERC Board of Trustees or a Board committee pursuant to Section 8(d) of this Agreement, in implementing this program.

~~(c) [REGIONAL ENTITY] shall report promptly to NERC any Possible Violation, Alleged Violation, or Confirmed Violation of a Reliability Standard, and its eventual disposition by [REGIONAL ENTITY]. Such report shall include the owner's, operator's, or user's name, which Reliability Standard or Reliability Standards were the subject of the Possible Violation, Alleged Violation, or Confirmed Violation, when the Possible Violation, Alleged Violation, or Confirmed Violation occurred, other pertinent facts including circumstances surrounding the Possible Violation, Alleged Violation, or Confirmed Violation with any known risk to the Bulk Power System, when the Possible Violation, Alleged Violation, or Confirmed Violation was or will be mitigated, the name of a person knowledgeable about the Possible Violation, Alleged Violation, or Confirmed Violation to serve as a point of contact with the Commission, and any other information required by NERC compliance program procedures. NERC shall promptly forward such report to the Commission. NERC and [REGIONAL ENTITY] shall cooperate in filing such periodic summary reports as the Commission shall from time to time direct on Possible Violations, Alleged Violations, and Confirmed Violations of Reliability Standards and summary analyses of such Possible Violations, Alleged Violations, and Confirmed Violations.~~

~~(d) Each Possible Violation, Alleged Violation, or Confirmed Violation shall be treated as nonpublic unless the matter is filed with the Commission as a Notice of Penalty, or, if disclosure is required, dismissed. The disposition of each Possible Violation, Alleged Violation, or Confirmed Violation that relates to a Cybersecurity Incident or that would~~

jeopardize the security of the Bulk-Power System if publicly disclosed shall remain nonpublic unless the Commission directs otherwise.

(e) All dispositions by [REGIONAL ENTITY] of Possible Violations, Alleged Violations, and Confirmed Violations of Reliability Standards shall be reported to NERC for review and, in the case of Confirmed Violations, penalties or sanctions, and settlements, for approval. Following approval of a disposition by NERC, NERC shall file the disposition with the Commission, if required by, and in accordance with, Section 215(e) of the Act and Section 39.7 of the ERO Regulations. NERC shall review [REGIONAL ENTITY]'s dispositions based on the following criteria:

(i) whether the disposition is supported by a sufficient record compiled by [REGIONAL ENTITY] in accordance with the NERC Rules of Procedure, NERC directives and Commission requirements, taking into account the nature of the Possible Violation, Alleged Violation, or Confirmed Violation,

(ii) whether the disposition is consistent with any applicable directives issued pursuant to Section 8(c) of this Agreement, any applicable directions or guidance issued by the NERC Board or a Board committee pursuant to Section 8(d) of this Agreement, or other applicable NERC guidance, concerning the Reliability Standards to which the Possible Violation, Alleged Violation, or Confirmed Violation relates,

(iii) if the disposition is a Confirmed Violation or settlement, whether it provides for a penalty or sanction, or a determination of no penalty or sanction, determined in accordance with the NERC Sanction Guidelines, Appendix 4B to the NERC Rules of Procedure, and

(iv) whether the disposition is reasonably consistent with other dispositions by [REGIONAL ENTITY] and by other Regional Entities of Possible Violations, Alleged Violations, and Confirmed Violations involving the same or similar facts and circumstances.

NERC may reject any disposition, with an explanation of why NERC believes the disposition does not meet the above criteria. [REGIONAL ENTITY] may submit a disposition requiring NERC approval that has been rejected by NERC, or a revised disposition following a rejection, directly to the NERC Board Compliance Committee for approval without revising the disposition to address all the grounds on which NERC originally rejected the disposition. The

~~final approval of [REGIONAL ENTITY]'s disposition of a Possible Violation, Alleged Violation, or Confirmed Violation shall be made by the NERC Board Compliance Committee, provided, that the NERC Board or NERC Board Compliance Committee may, by appropriate resolution, delegate authority for final approval of dispositions of specified categories of Possible Violations, Alleged Violations, or Confirmed Violations to the NERC President.~~

~~(f) All appeals of penalties imposed by [REGIONAL ENTITY] as a result of a decision by [REGIONAL ENTITY]'s Hearing Body shall be filed with, heard by and disposed of by, NERC in accordance with the NERC Rules of Procedure.~~

~~(g) [REGIONAL ENTITY] shall maintain the capability to conduct investigations of Possible Violations and Alleged Violations of Reliability Standards and to conduct such investigations in a confidential manner.~~

~~(h)~~(b) [REGIONAL ENTITY] shall maintain a program of proactive monitoring and enforcement of compliance with Reliability Standards, in accordance with the NERC Compliance Monitoring and Enforcement Program and the annual ~~NERC~~ERO Compliance Monitoring and Enforcement Program Implementation Plan.

(c) [REGIONAL ENTITY] shall report promptly to NERC information regarding noncompliance with a Reliability Standard, and its eventual disposition by [REGIONAL ENTITY], as set forth in, and subject to the confidentiality and disclosure provisions of, the NERC Rules of Procedure, the NERC Compliance Monitoring and Enforcement Program, this Agreement, compliance and enforcement program procedures and guidance that NERC may from time to time develop in collaboration with the Regional Entities, and the ERO Regulations. NERC shall promptly forward such report to the Commission, as required by the ERO Regulations, or as the Commission shall from time to time direct. NERC and [REGIONAL ENTITY] shall cooperate in filing such periodic summary reports and analyses as the Commission shall from time to time direct.

(d) All dispositions by [REGIONAL ENTITY] of noncompliance with Reliability Standards shall be reported to NERC for review. NERC, in collaboration with the Regional Entities, shall develop and implement policies and procedures for the review and, where appropriate, approval of dispositions of noncompliance.

~~(i)~~(e) As part of its compliance monitoring and enforcement program, [REGIONAL ENTITY] shall maintain a conflict of interest policy that assures the integrity and independence

of such program, including the integrity and independence of the persons or decision-making bodies making final determinations in compliance enforcement actions under Section 5.0 of the NERC Compliance Monitoring and Enforcement Program. A Regional Entity may have stakeholders lead or participate in its board compliance committee so long as integrity and independence are assured through reasonable and appropriate recusal procedures.

~~(j) As often as NERC deems necessary, but no less than every five years, NERC shall review [REGIONAL ENTITY]'s compliance monitoring and enforcement program to determine that: (i) the program meets all applicable legal requirements; (ii) actual practices reflect the requirements; and (iii) the program administered pursuant to the Delegated Authority promotes consistent interpretations across North America of Reliability Standards and comparable levels of sanctions and penalties for violations of Reliability Standards constituting comparable levels of threat to reliability of the Bulk Power System.~~

(f) [REGIONAL ENTITY] may also perform compliance monitoring and enforcement activities outside of the boundaries shown on **Exhibit A**, on behalf of a Regional Entity that is unable to perform such activities with respect to one or more registered entities within its footprint due to a conflict of interest. Such activities shall be performed pursuant to a contract between [REGIONAL ENTITY] and other such Regional Entity that is approved by both NERC and the Commission.

7. Delegation-Related Activities.

NERC will engage [REGIONAL ENTITY] on its behalf to carry out certain of its activities that are in furtherance of Bulk-Power System reliability and NERC's responsibilities as the ERO under the Act or in support of the Delegated Authority, as specified in the NERC Rules of Procedure and listed on **Exhibit E**. NERC may from time to time develop policies or procedures in collaboration with [REGIONAL ENTITY] and the other Regional Entities, which shall be used by [REGIONAL ENTITY] in the performance of the delegation-related activities. These delegation-related activities shall include, but are not limited to, those described in subsections (a) through (g~~f~~), each of which shall be considered a statutory activity:

(a) **Certification of Bulk-Power System Entities.** The NERC Board of Trustees shall set criteria for certification in accordance with the NERC Rules of Procedure. ~~[REGIONAL ENTITY]~~ Certifications shall ~~issue certifications~~be issued in accordance with the NERC Rules of Procedure.

(b) **Registration of owners, operators, and users of the Bulk-Power System as responsible for compliance with requirements of Reliability Standards.**

(i) The NERC Board of Trustees shall develop criteria for registration of owners, operators, and users of the Bulk-Power System as Registered Entities and shall apply the registration criteria to register owners, operators and users of the Bulk-Power System as Registered Entities.

(ii) NERC shall maintain a registration database of Registered Entities, based on data and information provided by [REGIONAL ENTITY] and other Regional Entities. [REGIONAL ENTITY] shall provide timely and accurate information relating to registrations to NERC, ~~on at least a monthly basis~~as needed, to enable NERC to maintain a registration database that is accurate and up-to-date.

(iii) The NERC Board of Trustees Compliance Committee shall hear and

decide appeals from owners, operators and users of the Bulk-Power System contesting registration, in accordance with the NERC Rules of Procedure. If the NERC Board of Trustees Compliance Committee upholds the decision to register an owner, operator, or user, NERC shall defend the decision in any subsequent appeal of the decision by the Registered Entity to the Commission.

(c) **Reliability Assessment and Performance Analysis.** [REGIONAL ENTITY] shall develop assessments of the reliability of the Bulk-Power System, or ensure that data and information are collected, analyzed and provided to NERC in support of the development of reliability assessments, in accordance with the NERC Rules of Procedure. [REGIONAL ENTITY] shall also develop and maintain, and collect data in support of the development and maintenance of, reliability performance metrics and assessments of risks to the Reliable Operation of the Bulk-Power System, in accordance with the NERC Rules of Procedure, NERC directives, and policies and procedures related to data-gathering, quality control, forms, and reporting mechanisms that NERC may from time to time develop in collaboration with the Regional Entities.

~~Operation of the Bulk-Power System, in accordance with the NERC Rules of Procedure and NERC directives. NERC shall develop data-gathering quality control procedures, forms and reporting mechanisms, which shall be used by [REGIONAL ENTITY] and other Regional Entities in carrying out their responsibilities under this subsection (c).~~

(d) **Event Analysis and Reliability Improvement.** [REGIONAL ENTITY] shall conduct event analysis pursuant to the NERC Rules of Procedure ~~and~~, applicable governmental regulations, and policies and procedures that NERC may from time to time develop in collaboration with [REGIONAL ENTITY] and the other Regional Entities. NERC and [REGIONAL ENTITY] shall coordinate event analysis to support the effective and efficient use of their collective resources, consistency in event analysis, and timely delivery of event analysis reports. In collaboration with NERC, [REGIONAL ENTITY] shall disseminate to the electric industry lessons learned and other information obtained or resulting from event analysis.

(e) **Training and Education.** [REGIONAL ENTITY] may provide training and education to Registered Entities, as it deems necessary, in support of its performance of delegated functions and related activities under this Agreement. NERC may also provide training and education programs to Registered Entities on topics relating to NERC's responsibilities as the ERO.

~~(f)~~ Situation Awareness ~~and Infrastructure Security.~~

~~(g)~~(f) . [REGIONAL ENTITY] shall gather and assess situation awareness information provided by Registered Entities pursuant to the NERC Rules of Procedure ~~and~~, applicable governmental regulations, and policies and procedures that NERC may from time to time develop in collaboration with [REGIONAL ENTITY] and the other Regional Entities, and shall provide other data, information and assistance to NERC in support of NERC's activities in monitoring present conditions, and responding to events, on the Bulk-Power System.

~~(h)~~(g) **Critical Infrastructure Security.** [REGIONAL ENTITY] shall collaborate with NERC in its efforts to coordinate electric industry activities to promote critical infrastructure protection of the Bulk-Power System in North America.

8. Oversight of Performance of Delegated Functions and Related Activities.

This Section 8 sets forth processes and procedures which the Parties intend shall be used in NERC's oversight of [REGIONAL ENTITY]'s performance of its Delegated Authority and

related activities pursuant to this Agreement. It is the intent of NERC and [REGIONAL ENTITY] that matters relating to NERC's oversight of [REGIONAL ENTITY]'s performance of its Delegated Authority and related activities shall be established or resolved by collaboration

between NERC and [REGIONAL ENTITY] and, where applicable, other Regional Entities, to the maximum extent possible, consistent with the construct that NERC and the Regional Entities are operating together in a collaborative manner to carry out the responsibilities of the ERO under Section 215 of the Act and the ERO Regulations.

(a) (i) NERC shall develop, in collaboration with [REGIONAL ENTITY] and other Regional Entities, performance goals, performance reports, measures and other parameters (including, without limiting the scope of such goals, ~~measures and parameters,~~ financial performance goals~~, measures and parameters), and performance reports,~~), which shall be used to measure NERC's and [REGIONAL ENTITY]'s performance of their respective functions and related activities. The performance goals, measures and parameters and the form of performance reports shall be approved by the NERC President and shall be made public. [REGIONAL ENTITY] shall provide data, information and reports to NERC, in accordance with established schedules, to enable NERC to calculate [REGIONAL ENTITY]'s performance to the agreed-upon goals, measures and parameters.

(ii) NERC shall use the performance goals, measures and parameters, and performance reports to evaluate [REGIONAL ENTITY]'s performance of its delegated functions and related activities and to provide advice and direction to [REGIONAL ENTITY] on performance improvements. The performance goals, measures and other parameters, and the values of such goals, measures and parameters, shall be reviewed by NERC, [REGIONAL ENTITY] and the other Regional Entities, revised if appropriate, and made public, on the same timeline as the annual business planning and budgeting process described in Section 9 of this Agreement.

~~(iii)~~ At the request of the President of NERC, [REGIONAL ENTITY] shall be required to develop, submit for NERC approval, and implement action plans to address, areas of its performance that are reasonably determined by NERC, based on analysis of [REGIONAL ENTITY]'s performance against the performance goals, measures and parameters, or performance of specific activities, to be unsatisfactory, *provided*, that prior to requiring [REGIONAL ENTITY] to adopt and implement an action plan or other remedial action, NERC shall issue a notice to [REGIONAL ENTITY] of the need and basis for an action plan or other remedial action and provide an opportunity for [REGIONAL ENTITY] to submit a written response contesting NERC's evaluation of [REGIONAL ENTITY]'s performance and the need

~~(iv)~~(iii) for an action plan. [REGIONAL ENTITY] may request that the President of NERC reconsider the request, and thereafter may request that the NERC Board of Trustees review and reconsider the request. NERC and [REGIONAL ENTITY] shall work collaboratively as needed in the development and implementation of [REGIONAL ENTITY]'s action plan. A final action plan submitted by [REGIONAL ENTITY] to NERC shall be made public unless the President of NERC makes a written determination that the action plan or specific portions of the plan should be maintained as non-public.

(b) NERC shall make available to [REGIONAL ENTITY] standardized training and education programs, which shall be designed taking into account input from [REGIONAL ENTITY] and other Regional Entities, for [REGIONAL ENTITY] personnel on topics relating to the delegated functions and related activities.

(c) (i) NERC may issue directives to [REGIONAL ENTITY] concerning the manner in which [REGIONAL ENTITY] shall perform its delegated functions and related activities under this Agreement. The NERC Rules of Procedure, or any other ERO Rule requiring approval of the Commission, shall not be considered "directives." NERC shall initiate the development of a directive through a collaborative process with [REGIONAL ENTITY] and, if applicable, other Regional Entities to which the directive will apply. Any directive developed through the collaborative process shall be approved by, and issued under the signature of, the NERC President.

(ii) If after a period of time that is reasonable under the circumstances, NERC and [REGIONAL ENTITY] and, if applicable, other Regional Entities are unable to reach agreement on the contents of the directive, NERC may issue the directive with the approval of and under the signature of the NERC President; *provided*, that before the NERC President issues a directive pursuant to this paragraph (ii), [REGIONAL ENTITY] and, if applicable, other Regional Entities, shall be given a reasonable opportunity to present their positions on, and a suggested alternative version or versions of, the proposed directive to the NERC President.

~~(iii)~~ Upon issuance of a directive by the NERC President, it shall be binding upon, and shall be complied with by, [REGIONAL ENTITY], subject to reasonable time periods for adoption, implementation, and funding of any necessary resources. Upon request by [REGIONAL ENTITY], the NERC Board of Trustees (or a committee of the Board to which the Board

~~(iv)~~(iii) delegates appropriate authority) shall review and shall confirm, revise or revoke any directive that was issued by the NERC President without [REGIONAL ENTITY]'s agreement, *provided*, that [REGIONAL ENTITY] shall request such review within thirty (30) days following issuance of the directive by the NERC President unless good cause can be shown for a later request.

~~(v)~~(iv) NERC and [REGIONAL ENTITY] and, if applicable, other Regional Entities, shall collaborate in deciding whether a directive (whether issued pursuant to paragraph
(ii) or paragraph (iii)) shall be made public. If no agreement is reached by the date of issuance as to whether the directive shall be made public, the NERC President shall decide whether the directive will be made public, *provided*, that it is the intent of the Parties that the NERC President shall apply a presumption that directives should be made public, unless the NERC President makes a written determination stating a specific reason for maintaining a particular directive as non-public.

(d) In addition to the issuance of directives pursuant to subsection (c), the NERC Board of Trustees (or a Board committee to which the Board has delegated authority) may issue guidance or directions as to the manner in which [REGIONAL ENTITY], and, if applicable, other Regional Entities, shall perform delegated functions and related activities. The NERC Board of Trustees or Board committee shall also establish reasonable time periods for the implementation of any such guidance or directions, taking into account the impact on the reliability of the Bulk-Power System and the need for funding of additional resources. Any such guidance or directions shall be stated in writing and shall be public, unless the NERC Board of Trustees or Board committee makes a written determination stating a specific reason for maintaining particular guidance or directions as non-public. [REGIONAL ENTITY], either individually or in conjunction with other Regional Entities, may request that the NERC Board of Trustees or Board committee reconsider or revise the guidance or direction.

(e) NERC shall conduct collaborative reviews with [REGIONAL ENTITY], either individually or in conjunction with one or more other Regional Entities, that provide for the exchange of information on practices, experiences, and lessons learned in the implementation of the delegated functions.

~~(f) Any audits~~NERC may perform reviews of [REGIONAL ENTITY] ~~performed by NERC shall be limited~~on a reasonable periodicity to ~~an examination of~~determine the

[REGIONAL ENTITY]'s compliance with this Agreement, any policies or procedures established by NERC, NERC's Rules of

~~(g)~~(f) Procedure, the Compliance Monitoring and Enforcement Program, Commission requirements, and directives that are in effect pursuant to Section 8(c~~).~~) and to monitor the implementation of guidance and directions issued by the NERC Board of Trustees pursuant to Section 8(d). All such periodic reviews shall comply with the NERC Rules of Procedure and Commission directives.

~~(h)~~(g) The Commission and the Commission staff shall have full access to action plans and remedial actions, directives, and directions and guidance issued pursuant to subsections (a)(iii), (c)(iv) and (d), respectively, that are maintained as non-public.

9. Funding. [REGIONAL ENTITY] and NERC shall ensure, subject to Commission approval in accordance with the ERO Regulations, that the delegated functions and related activities described in Sections 5, 6 and 7 and listed on **Exhibit E** have reasonable and adequate funding and resources by undertaking the following:

(a) [REGIONAL ENTITY] shall develop, through a collaborative process with NERC, and propose, an annual business plan and budget, in accordance with ERO Regulations, Commission orders and NERC business planning and budgeting policies and instructions. [REGIONAL ENTITY]'s proposed business plan and budget shall describe the activities necessary for, and provide a budget with adequate resources for, [REGIONAL ENTITY] to carry out its Delegated Authority under this Agreement, including the functions and activities described in Sections 5, 6 and 7 and listed on **Exhibit E**. [REGIONAL ENTITY]'s business plan and budget shall show the funding sources and amounts to fund the proposed budget, including as applicable assessments to end users, penalty monies, and other sources of funds.

~~(b)~~ [REGIONAL ENTITY] and NERC agree that the portion of [REGIONAL ENTITY]'s approved budget for the functions and activities described in Sections 5, 6 and 7 and listed on **Exhibit E** that is to be funded by assessments, will be equitably allocated among end users within the geographic boundaries described in **Exhibit A** and recovered through a formula based on Net Energy for Load, or through such other formula as is proposed by [REGIONAL ENTITY] and approved by NERC and the Commission. If [REGIONAL ENTITY] proposes to use a formula other than Net Energy for Load beginning in the following year, [REGIONAL ENTITY] shall submit the proposed formula to NERC in sufficient time that NERC may review and approve the proposed formula and file it with the Commission by May 15 for approval, and the proposed formula shall be effective for the following year if approved

by the Commission on or before the date the Commission approves the annual business plan and

~~(c)~~(b) budget submitted by NERC and [REGIONAL ENTITY] to the Commission pursuant to the ERO Regulations for such year.

~~(d)~~(c) NERC shall determine that the assessments to fund the costs for its statutory functions in its Commission-approved budget are first allocated fairly among the Interconnections and regions according to the applicability of this work to those Interconnections and regions, and then equitably among the end users of the applicable interconnections and regions as appropriate. Allocation on a Net Energy for Load basis will be presumed to satisfy this equitability requirement.

~~(e)~~(d) NERC shall provide [REGIONAL ENTITY] with the form or forms for business plan and budget submittal, and any accompanying instructions, in accordance with the schedule for preparation of the business plan and budget developed by NERC and the Regional Entities.

~~(f)~~(e) [REGIONAL ENTITY] shall submit its proposed annual business plan and budget for carrying out its Delegated Authority functions and related activities described in Sections 5, 6 and 7 and listed on **Exhibit E**, as well as for all other activities of [REGIONAL ENTITY], to NERC for review and approval in accordance with the annual schedule for the preparation of business plans and budgets which shall be developed collaboratively by NERC and the Regional Entities, as more fully described in **Exhibit E**.

~~(g)~~(f) NERC shall fund [REGIONAL ENTITY]'s performance of its Delegated Authority and related activities in accordance with [REGIONAL ENTITY]'s Commission-approved business plan and budget, in the amount of [REGIONAL ENTITY]'s assessments to end users approved by the Commission. **Exhibit E** sets forth the procedures and timing for billing and collecting [REGIONAL ENTITY]'s approved assessments from end users and other entities and payment of the approved assessment amount to [REGIONAL ENTITY], unless otherwise modified and approved by NERC and the Commission. NERC shall not impose any material obligation or requirement regarding the Delegated Authority upon [REGIONAL ENTITY] that has not been provided for in an approved business plan and budget or an approved amended or supplemental business plan and budget, without [REGIONAL ENTITY]'s consent.

~~(h)~~ NERC shall develop, in consultation with the Regional Entities, a reasonable and consistent system of accounts, with a level of detail and record keeping comparable to the Commission's Uniform System of Accounts and sufficient to allow the Commission to compare

~~(i)~~(g) each Commission-approved NERC and [REGIONAL ENTITY] fiscal year budget with the actual results at the NERC and Regional Entity levels. [REGIONAL ENTITY] shall follow NERC's prescribed system of accounts except to the extent that NERC permits a departure from the prescribed system of accounts. NERC shall make an informational filing with the Commission describing any such waiver it permits and providing an explanation supporting the permitted departure.

~~(j)~~(h) [REGIONAL ENTITY] shall submit unaudited quarterly interim financial statements in form provided by NERC no later than 20 days after the end of the fiscal quarter (March 31, June 30, September 30, and December 31).

~~(k)~~(i) [REGIONAL ENTITY] shall submit audited financial statements annually, including supporting materials, in a form provided by NERC ~~no later than May 1 of the following year~~, by no later than the date reasonably required and designated in writing by NERC to enable NERC to assemble and file the required annual budget to actual true up filing with the Commission.

~~(l)~~(j) **Exhibit E** to this Agreement sets forth the mechanism through which [REGIONAL ENTITY] shall offset penalty monies it receives (other than penalty monies received from an operational function or division or affiliated entity of [REGIONAL ENTITY]) against its next year's annual budget for carrying out functions under this Agreement, and the mechanism by which [REGIONAL ENTITY] shall transmit to NERC any penalty monies received from an operational function or division or affiliated entity of [REGIONAL ENTITY]. *Provided*, that, subject to approval by NERC and the Commission, [REGIONAL ENTITY] may propose and implement an alternative use of penalty monies to that set forth in **Exhibit E**.

10. Assignment. This Agreement may be assigned by either Party only with the prior written consent of the other, which consent shall be granted or withheld in such non-assigning Party's sole discretion, subject to approval by the Commission. Any assignment under this Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. [REGIONAL ENTITY] may not delegate in whole or in part its Delegated Authority to any other entity without NERC's express consent; provided, however, that nothing in this provision shall prohibit [REGIONAL ENTITY] from contracting with other entities to assist it in carrying out its Delegated Authority, provided [REGIONAL ENTITY] retains control and responsibility for such Delegated Authority.

11. Default and Cure. Upon a Breach, the non-breaching Party shall give written notice of such Breach to the breaching Party (the "Default Notice"). Subject to a suspension of the following deadlines as specified below, the breaching Party shall have thirty (30) calendar days from receipt of the Default Notice within which to cure such Breach; *provided however*, that if such Breach is not capable of cure within thirty (30) calendar days, the breaching Party shall commence such cure within thirty (30) calendar days after notice and continuously and diligently complete such cure within ninety (90) calendar days from receipt of the Default Notice; and, if cured within such time, the Breach specified in such notice shall cease to exist. Subject to the limitation specified in the following sentence, if a Breach is not cured as provided in this Section 11, or if a Breach is not capable of being cured within the period provided for herein, the nonbreaching Party shall have the right to declare a default and terminate this Agreement by written notice at any time until cure occurs, and be relieved of any further obligation hereunder. ~~-~~The deadlines for cure and the right to declare a default and terminate this Agreement shall be suspended during the pendency of any efforts or proceedings in accordance with Section 18 of this Agreement to resolve a dispute as to whether a Breach has occurred or been cured. The provisions of this Section 11 will survive termination of this Agreement.

12. Term and Termination.

(a) This Agreement shall become effective on [January 1, ~~2011~~2016] (the "Effective Date").

~~Date").~~

~~(b)~~ The term of ~~the~~this Agreement shall ~~be five (5) years from~~commence on the Effective Date, ~~prior~~

~~(c)~~(b) ~~to which time NERC shall conduct an audit pursuant to subsection 6(i) to ensure that [REGIONAL ENTITY] continues to meet all applicable statutory and regulatory requirements necessary to maintain its eligibility~~and shall have initial term of five years (the "Term"), ending on December 31, 2020. Thereafter, the Term shall automatically extend for ~~delegation. If [REGIONAL ENTITY] meets such requirements, this Agreement may be renewed for another five (5) year term. This Agreement may be renewed for successive~~ one additional five ~~(5) year renewal terms provided that prior to the end of each renewal term, NERC shall conduct an audit pursuant to subsection 6(i) to ensure that [REGIONAL ENTITY] continues to meet all applicable statutory and regulatory requirements necessary to maintain its eligibility for delegation. Provided, that~~-year term unless either Party ~~may~~

~~terminate~~ shall provide written notice of termination of this Agreement ~~as of~~to the ~~end of a term by giving written notice to terminate at least one (1)~~other no later than one year prior to the ~~end~~then effective expiration of the ~~term. If~~Term. In such event, this Agreement ~~is not renewed or becomes subject~~shall terminate upon the expiration of then effective Term, unless otherwise mutually agreed to by the Parties.

~~(d)~~(c) ~~to~~In the event of the termination ~~for any reason~~of this Agreement, the Parties shall work to provide for a transition of [REGIONAL ENTITY]'s Delegated Authority to NERC or to another eligible entity and to provide for the resolution of any wind-up costs associated with termination of this Agreement. ~~The termination of this Agreement shall not take effect until such transition has been effected, unless the transition period exceeds one year, at which time [REGIONAL ENTITY] may unilaterally terminate.~~

~~(e)~~(d) If any provision of this Agreement, or the application thereof to any person, entity or circumstance, is held by a court or regulatory authority of competent jurisdiction to be invalid, void, or unenforceable, or if a modification or condition to this Agreement is imposed by a regulatory authority exercising jurisdiction over this Agreement, the Parties shall endeavor in good faith to negotiate such amendment or amendments to this Agreement as will restore the relative benefits and obligations of the signatories under this Agreement immediately prior to such holding, modification or condition. If either Party finds such holding, modification or condition unacceptable and the Parties are unable to renegotiate a mutually acceptable resolution, either Party may unilaterally terminate this Agreement. Such termination shall be effective one year following written notice by either Party to the other Party and to the Commission, or at such other time as may be mutually agreed by [REGIONAL ENTITY] and NERC.

~~(f)~~(e) Notwithstanding any termination of this Agreement, provisions contained in Limitation of Liability (Section 13), No Third Party Beneficiaries (Section 14) and Confidentiality (Section 15) shall survive this Agreement in accordance with their terms until sixty (60) days following the expiration of any applicable statute of limitations.

~~13.~~ **Limitation of Liability**. [REGIONAL ENTITY] and NERC agree not to sue each other or their directors, officers, employees, and persons serving on their committees and subgroups based on any act or omission of any of the foregoing in the performance of duties pursuant to this Agreement or in conducting activities under the authority of Section 215 of the Act, other than seeking a review of such action or inaction by the Commission. NERC and [REGIONAL ENTITY] shall not be liable to one another for any damages whatsoever, including without limitation, direct, indirect, incidental, special, multiple, consequential (including attorneys' fees and litigation costs), exemplary, or punitive damages arising out of or resulting from any act or

~~14.~~13. omission associated with the performance of the [REGIONAL ENTITY]'s or NERC's responsibilities under this Agreement or in conducting activities under the authority of Section 215 of the Act, except to the extent that the [REGIONAL ENTITY] or NERC is found liable for gross negligence or intentional misconduct, in which case [REGIONAL ENTITY] or NERC shall not be liable for any indirect, incidental, special, multiple, consequential (including without limitation attorneys' fees and litigation costs), exemplary, or punitive damages.

~~15.~~14. **No Third Party Beneficiaries.** Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to, any third party~~.~~, except as otherwise specifically provided herein and in section 15(c).

15. Confidentiality.

(a) During the course of the Parties' performance under this Agreement, a Party may receive proprietary, business sensitive, or critical infrastructure information ("Confidential Information~~, as defined~~") necessary to fulfill their respective obligations in ~~Section 1500~~connection with this Agreement. The Parties agree that their mutual objective under this provision is to provide appropriate protection for Confidential Information, while maintaining the ability to conduct their respective business activities.

(b) No obligation of ~~NERC's Rules of Procedure.~~ confidentiality shall apply to any information that the recipient: (i) already possesses without obligation of confidentiality; (ii) develops independently; or (iii) rightfully receives without any obligation of confidentiality from a third party.

(c) The Parties may transfer or exchange such Confidential Information with and between the other Regional Entities as third-party beneficiaries of the terms of this Agreement, providing the Parties continue to maintain the confidentiality of such information.

(d) Except as set forth herein and within the NERC Rules of Procedure, the Parties agree to keep in confidence and not to copy, disclose, or distribute any Confidential Information or any part thereof, without the prior written permission of the issuing Party or specified third-party beneficiary of this Agreement, unless disclosure is required by subpoena, law, or other directive of a court, administrative agency, or arbitration panel, in which event the recipient hereby agrees to provide the Party or specified third-party beneficiary of this Agreement that

provided the Confidential Information with prompt notice of such request or requirement in order to enable such issuing Party or specified third-party beneficiary of this Agreement to (a) seek an appropriate protective order or other remedy, (b) consult with the recipient with respect to taking steps to resist or narrow the scope of such request or legal process, or (c) waive compliance, in whole or in part, with the terms of this Section. In the event a protective order or other remedy is not obtained or the issuing Party or specified third-party beneficiary of this Agreement waives compliance with the provisions, the recipient agrees to furnish only that portion of the Confidential Information which the recipient's counsel advises is legally required and to exercise best efforts to obtain assurance that confidential treatment will be accorded to such Confidential Information. ~~In addition, each~~

(e) Each Party shall ensure that its officers, trustees, directors, employees, subcontractors and subcontractors' employees, and agents to whom Confidential Information is exposed are under obligations of confidentiality that are at least as restrictive as those contained herein.

(f) This confidentiality provision does not prohibit reporting and disclosure as directed by NERC, as set forth in Section 6 of this Agreement, nor does it prohibit permitted disclosures as set forth in the NERC Rules of Procedure.

16. Amendment. Neither this Agreement nor any of the terms hereof, may be amended unless such amendment is made in writing, signed by the Parties, and filed with and approved by the Commission.

17. Amendments to the NERC Rules of Procedure. NERC shall not adopt amendments to the NERC Rules of Procedure that conflict with the rights, obligations, or programs of [REGIONAL ENTITY] under this Agreement without first obtaining the consent of [REGIONAL ENTITY], which consent shall not be unreasonably withheld or delayed. To the extent [REGIONAL ENTITY] does not consent, NERC shall have the right to invoke the dispute resolution provisions of Section 18 and, if such effort fails to resolve the dispute, to petition the Commission to adopt the amendment to the NERC Rules of Procedure. To the extent that the Commission issues an order amending or materially affecting the rights or obligations of [REGIONAL ENTITY] under this Agreement, [REGIONAL ENTITY] shall have the option, exercisable no later than 60 days after issuance of such order, to terminate this Agreement. Such termination shall be effective one year following written notice by [REGIONAL ENTITY] to NERC and the Commission, or at such other time as may be mutually agreed by [REGIONAL ENTITY] and NERC.

18. Dispute Resolution. In the event a dispute arises under this Agreement between NERC and [REGIONAL ENTITY] (including disputes relating to NERC's performance of its obligations under this Agreement and/or disputes relating to [REGIONAL ENTITY]'s performance of its obligations under this Agreement) which cannot be resolved through discussions between representatives of the Parties in the normal course of operations, the Parties shall use the following procedures ("Dispute Resolution") to attempt to resolve the dispute. [REGIONAL ENTITY] shall not suspend performance of any delegated function, and the Parties shall continue to make reasonable, good faith efforts to comply with their obligations under this Agreement, during the pendency of Dispute Resolution. All notices required to be sent pursuant to this Dispute Resolution procedure shall be sent in accordance with Section 19 of this Agreement. This Dispute Resolution procedure is separate from and in addition to all other processes provided for in this Agreement.

(a) The Party invoking Dispute Resolution shall send a notice to the other Party describing the dispute, stating the invoking Party's position with respect to the dispute, stating that the Party is invoking Dispute Resolution, and naming the Party's designated representative for negotiating a resolution of the dispute. The designated representative shall have authority to resolve the dispute on behalf of the invoking Party.

(b) Within three (3) business days after receipt of the notice invoking Dispute Resolution, the receiving Party shall send a notice to the invoking Party acknowledging receipt of the notice invoking Dispute Resolution, stating the receiving Party's position with respect to the dispute, and naming the Party's designated representative for negotiating a resolution of the dispute. The designated representative shall have authority to resolve the dispute on behalf of the receiving Party.

(c) During the period commencing three (3) business days and ending twenty (20) business days after the date of the receiving Party's notice, the designated representatives shall engage in good faith negotiations to attempt to resolve the dispute, *provided*, that the designated representatives may agree prior to the end of such twenty (20) business day period that the process should move to the next step of Dispute Resolution.

(d) If the designated representatives are unable to arrive at a resolution of the dispute by the end of the time period described in subsection (c), they shall notify the chief executive officers of their respective Parties. The chief executive officers of the Parties shall thereafter engage in good faith negotiations to attempt to resolve the dispute during the period of twenty (20) business days immediately following the time period described in subsection (c), *provided*, that the chief executive officers may agree prior to the end of such twenty (20) business day period that negotiations are at impasse and the process may move to the next step as described in subsection (f). Upon mutual agreement of the Parties, the twenty (20) business day period may be extended to pursue ongoing good faith negotiations.

(e) If a resolution of the dispute is achieved by the Parties, it shall be memorialized in a writing that is acceptable in form and substance to each party and is signed by the designated representative or chief executive officer on behalf of each Party.

~~(f)~~ If the Parties are unable to resolve the dispute pursuant to the process described in subsections (a) through (e), then either Party may invoke any other available dispute resolution mechanism, including, without limitation, filing a complaint or petition with the Commission

requesting resolution of the dispute by the Commission, or filing a complaint for relief in a court having jurisdiction over Parties and the subject matter of the dispute in accordance with Section ~~(g)~~(f) 20. *Provided, however*, that: (i) it is the intent of the Parties that unresolved disputes shall be presented to and resolved by the Commission if the Commission has and accepts jurisdiction over the subject matter of the dispute, (ii) the Parties may, by mutual agreement, attempt to resolve the dispute through arbitration, mediation, or other process involving resort to an impartial neutral, and (iii) it is the intent of the Parties that resolution of disputes through Commission proceedings, arbitration, mediation, or other use of an impartial neutral, is preferred over resort to judicial proceedings.

~~(h)~~(g) This Section 18 shall not apply to compliance enforcement actions against individual Registered Entities.

19. Notice. ~~Whether expressly so stated or not, all~~All notices, demands, requests, and other communications required ~~or~~, permitted by, or provided for in this Agreement shall be given in writing to a Party at the address set forth below, or at such other address as a Party shall designate for itself in writing in accordance with this Section, and shall be delivered by hand, e-mail or ~~reputable~~ overnight courier:

If to NERC:	If to [REGIONAL ENTITY]:
North American Electric Reliability Corporation ~~116-390 Village Blvd. Princeton, NJ 08540-5721~~ 1325 G Street NW Suite 600 Washington, DC 20005	_____
Attn: General Counsel	Attn:
~~Facsimile: (609) 452-9550~~	~~Facsimile:~~
Email:	Email:

20. Governing Law. When not in conflict with or preempted by federal law, this Agreement will be governed by and construed in accordance with the laws of ~~New Jersey~~Georgia without giving effect to the conflict of law principles thereof. The Parties recognize and agree not to contest the exclusive or primary jurisdiction of the Commission to interpret and apply this Agreement; provided however that if the Commission declines to exercise or is precluded from exercising jurisdiction of any action arising out of or concerning

this Agreement, such action shall be brought in any state or federal court of competent jurisdiction in ~~New Jersey~~Georgia. All Parties hereby consent to the jurisdiction of any state or federal court of competent jurisdiction in Georgia for the purpose of hearing and determining any action not heard and determined by the Commission.

~~in New Jersey for the purpose of hearing and determining any action not heard and determined by the Commission.~~

21. Headings. The headings and captions in this Agreement are for convenience of reference only and shall not define, limit, or otherwise affect any of the terms or provisions hereof.

22. Savings Clause. Nothing in this Agreement shall be construed to preempt or limit any authority that [REGIONAL ENTITY] may have to adopt reliability requirements or take other actions to maintain reliability of the Bulk-Power System within the geographic boundaries described in **Exhibit A** that are outside the Delegated Authority, as long as such reliability requirements and actions are not inconsistent with Reliability Standards applicable to the region described in **Exhibit A** and do not result in a lessening of reliability outside the region described in **Exhibit A**.

23. Entire Agreement. This Agreement constitutes the entire agreement, and supersedes all prior agreements and understandings, both written and oral, among the parties with respect to the subject matter of this Agreement.

24. Execution of Counterparts. This Agreement may be executed in counterparts and each shall have the same force and effect as the original.

NOW THEREFORE, the parties have caused this Agreement to be executed by its duly authorized representatives, effective as of the Effective Date.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	[REGIONAL ENTITY]
By: _____	By: _____
Name: _____	Name: _____
Title: _____	Title: _____
Date: _____	Date: _____

Exhibit A — Regional Boundaries

Exhibit A to the delegation agreement for each Regional Entity receiving Delegated Authority shall describe the geographic or electrical boundaries covered by the proposed delegation of authority. **Exhibit A** for each Regional Entity shall reflect coordination with neighboring Regional Entities, as appropriate, to ensure that all relevant areas are either included within the geographic boundaries of a Regional Entity or specifically identified as not being within the geographic boundaries of any Regional Entity. Any exclusions of geographic or electrical areas or of Registered Entities from the scope of the Regional Entity's Delegated Authority within the geographic or electrical boundaries shown on **Exhibit A**, and any additions of geographic or electrical areas or of Registered Entities located outside the boundaries shown on **Exhibit A** to the scope of the Regional Entity's Delegated Authority, shall be specifically stated or described in **Exhibit A**.

Exhibit B – Governance

~~**Exhibit B shall set forth the Regional Entity's bylaws, which NERC agrees demonstrate that the**~~ **The Regional Entity** ~~**meets**~~ **bylaws shall meet the following criteria:**

CRITERION 1: The Regional Entity shall be governed by an independent board, a balanced stakeholder board, or a combination independent and balanced stakeholder board. (Federal Power Act § 215(e)(4)(A), 18 C.F.R. § 39.8(c)(1), Order No. 672 at ¶ 727.)

CRITERION 2: The Regional Entity has established rules that assure its independence ~~**of**~~ **from the users and owners and operators of the bulk power system, while assuring fair stakeholder representation in the selection of its directors.** Federal Power Act § 215(c)(2)(A) and (e)(4), 18 C.F.R. § 39.8(c)(2), Order No. 672 at ¶¶ 699, 700.)

CRITERION 3: If the Regional Entity has members, the Regional Entity has established rules that assure that its membership is open, that it charges no more than a nominal membership fee and agrees to waive the fee for good cause shown, and that membership is not a condition for participating in the development of or voting on proposed Regional Reliability Standards. (Federal Power Act § 215(c)(2)(A) and (e)(4), 18 C.F.R. § 39.8(c)(2), Order No. 672 at ¶¶ 170-173.)

CRITERION 4: The Regional Entity has established rules that assure balance in its decision-making committees and subordinate organizational structures and assure no two industry sectors can control any action and no one industry sector can veto any action. (Federal Power Act § 215(c)(2)(A) and (e)(4), 18 C.F.R. § 39.8(c)(2), Order No. 672 at ¶ 728.)

CRITERION 5: The Regional Entity has established rules that provide reasonable notice and opportunity for public comment, due process, openness, and balance of interests in exercising its duties. (Federal Power Act § 215(c)(2)(D) and (e)(4), 18 C.F.R. § 39.8(c)(2).)

EXHIBIT C [Intentionally left blank]

~~Exhibit C – Regional Standard Development Procedure~~

~~**Exhibit C shall set forth the Regional Entity's standards development procedure, which NERC agrees meets the following common attributes:**~~

~~**COMMON ATTRIBUTE 1**~~

~~Proposed regional reliability standards shall be subject to approval by NERC, as the electric reliability organization, and by FERC before becoming mandatory and enforceable under Section 215 of the FPA [add reference to any applicable authorities in Canada and Mexico]. No regional reliability standard shall be effective within the [Regional Entity Name] area unless filed by NERC with FERC [and applicable authorities in Canada and Mexico] and approved by FERC [and applicable authorities in Canada and Mexico].~~

~~**COMMON ATTRIBUTE 2**~~

~~[Regional Entity Name] regional reliability standards shall provide for as much uniformity as possible with reliability standards across the interconnected bulk power system of the North American continent. A [Regional Entity Name] reliability standard shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. A regional reliability standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable.~~

~~**COMMON ATTRIBUTE 3**~~

~~[Regional Entity Name] regional reliability standards, when approved by FERC [add applicable authorities in Canada], shall be made part of the body of NERC reliability standards and shall be enforced upon all applicable bulk power system owners, operators, and users within the [Regional Entity Name] area, regardless of membership in the region.~~

~~**COMMON ATTRIBUTE 4**~~

~~**Requester** ↓ The requester is the sponsor of the regional reliability standard request and may assist in the development of the standard. Any member of [Regional Entity Name], or group within [Regional Entity Name] shall be allowed to request that a regional reliability standard be developed, modified, or withdrawn. Additionally, any entity (person, organization, company, government agency, individual, etc.) that is directly and materially affected by the reliability of the bulk power system in the [Regional Entity Name] area shall be allowed to request a regional reliability standard be developed, modified, or withdrawn.~~

COMMON ATTRIBUTE 5

[Standards or other named] committee ↓ The [Regional Entity Name] [standards] committee manages the standards development process. The [standards] committee will consider which requests for new or revised standards shall be assigned for development (or existing standards considered for deletion). The [standards] committee will advise the [Regional Entity Name] board on standards presented for adoption.

COMMON ATTRIBUTE 6

[*Alternative 6A: For a Regional Entity that chooses to vote using a balanced stakeholder committee.*]

The [standards] committee is a balanced stakeholder committee, inclusive of all stakeholder interests that provide for or are materially impacted by the reliability of the bulk power system. [The [standards] committee votes to approve standards.] See Appendix A for the representation model of the [standards] committee.

[*Alternative 6B: For a Regional Entity that chooses to vote using a balanced ballot body of stakeholders.*]

[Registered ballot body ↓ The registered ballot body comprises all entities or individuals that qualify for one of the stakeholder segments; are registered with [Regional Entity Name] as potential ballot participants in the voting on standards; and are current with any designated fees. Each member of the registered ballot body is eligible to vote on standards. [Each standard action has its own ballot pool formed of interested members of the registered ballot body. Each ballot pool comprises those members of the registered ballot body that respond to a pre-ballot survey for that particular standard action indicating their desire to participate in such a ballot pool.] The representation model of the registered ballot body is provided in Appendix A.]

COMMON ATTRIBUTE 7

[Regional Entity Name] will coordinate with NERC such that the acknowledgement of receipt of a standard request identified in step 1, notice of comment posting period identified in step 4, and notice for vote identified in step 5 below are concurrently posted on both the [Regional Entity Name] and NERC websites.

COMMON ATTRIBUTE 8

An acceptable standard request shall contain a description of the proposed regional reliability standard subject matter containing sufficiently descriptive detail to clearly define the purpose, scope, impacted parties, and other relevant information of the proposed standard.

~~COMMON ATTRIBUTE 9~~

~~Within [no greater than 60] days of receipt of a completed standard request, the [standards] committee shall determine the disposition of the standard request.~~

~~COMMON ATTRIBUTE 10~~

~~The [standards] committee may take one of the following actions:~~

- ~~Accept the standard request as a candidate for development of a new standard, revision of an existing standard, or deletion of an existing standard. The [standards] committee may, at its discretion, expand or narrow the scope of the standard request under consideration. The [standards] committee shall prioritize the development of standard in relation to other proposed standards, as may be required based on the volume of requests and resources.~~

- ~~Reject the standard request. If the [standards] committee rejects a standard request, a written explanation for rejection will be delivered to the requester within [no greater than 30] days of the decision.~~

- ~~Remand the standard request back to the requester for additional work. The standards process manager will make reasonable efforts to assist the requester in addressing the deficiencies identified by the [standards] committee. The requester may then resubmit the modified standard request using the process above. The requester may choose to withdraw the standard request from further consideration prior to acceptance by the [standards] committee.~~

~~COMMON ATTRIBUTE 11~~

~~Any standard request that is accepted by the [standards] committee for development of a standard (or modification or deletion of an existing standard) shall be posted for public viewing on the [Regional Entity Name] website within [no greater than 30] days of acceptance by the committee.~~

~~COMMON ATTRIBUTE 12~~

~~The standards process manager shall submit the proposed members of the drafting team to the [standards] committee. The [standards] committee shall approve the drafting team membership within 60 days of accepting a standard request for development, modifying the recommendations of the standards process manager as the committee deems appropriate, and assign development of the proposed standard to the drafting team.~~

COMMON ATTRIBUTE 13

At the direction from the [standards] committee, the standards process manager shall facilitate the posting of the draft standard on the [Regional Entity Name] website, along with a draft implementation plan and supporting documents, for a no less than a [30] day comment period. The standards process manager shall provide notice to [Regional Entity Name] stakeholders and other potentially interested entities, both within and outside of the [Regional Entity Name] area, of the posting using communication procedures then currently in effect or by other means as deemed appropriate.

COMMON ATTRIBUTE 14

The drafting team shall prepare a summary of the comments received and the changes made to the proposed standard as a result of these comments. The drafting team shall summarize comments that were rejected by the drafting team and the reason(s) that these comments were rejected, in part or whole. The summary, along with a response to each comment received will be posted on the [Regional Entity Name] website no later than the next posting of the proposed standard.

COMMON ATTRIBUTE 15

Upon recommendation of the drafting team, and if the [standards] committee concurs that all of the requirements for development of the standard have been met, the standards process manager shall post the proposed standard and implementation plan for ballot and shall announce the vote to approve the standard, including when the vote will be conducted and the method for voting. Once the notice for a vote has been issued, no substantive modifications may be made to the proposed standard unless the revisions are posted and a new notice of the vote is issued.

COMMON ATTRIBUTE 16

The standards process manager shall schedule a vote by the [Regional Entity Name] [registered ballot body/[standards] committee]. The vote shall commence no sooner than [15] days and no later than [30] days following the issuance of the notice for the vote.

COMMON ATTRIBUTE 17

[Alternative *17A: For an RE that chooses to vote using a balanced stakeholder committee.*]

The [standards] committee shall give due consideration to the work of the drafting team, as well as the comments of stakeholders and minority objections, in approving a proposed regional reliability standard for submittal to the [Regional Entity Name] board. The [standards]

committee may vote to approve or not approve the standard. Alternatively, the [standards] committee may remand the standard to the drafting team for further work or form a new drafting team for that purpose.

[Alternative *17B: For an RE that chooses to vote using a balanced ballot body of stakeholders.*]

The [Regional Entity Name] registered ballot body shall be able to vote on the proposed standard during a period of [not less than 10] days.

COMMON ATTRIBUTE 18

[Alternative *18A: For an RE that chooses to vote using a balanced stakeholder committee.*]

The [standards] committee may not itself modify the standard without issuing a new notice to stakeholders regarding a vote of the modified standard.

[Alternative *18B: For an RE that chooses to vote using a balanced ballot body of stakeholders.*]

All members of [Regional Entity Name] are eligible to participate in voting on proposed new standards, standard revisions or standard deletions. [Alternatively: Each standard action requires formation of a ballot pool of interested members of the registered ballot body.]

COMMON ATTRIBUTE 19

[Alternative *19A: For an RE that chooses to vote using a balanced stakeholder committee.*]

Actions by the committee shall be recorded in the regular minutes of the committee.

[Alternative *19B: For an RE that chooses to vote using a balanced ballot body of stakeholders.*]

Approval of the proposed regional reliability standard shall require a [two thirds] majority in the affirmative (affirmative votes divided by the sum of affirmative and negative votes). Abstentions and non-responses shall not count toward the results, except that abstentions may be used in the determination of a quorum. A quorum shall mean [XX%] of the members of the [registered ballot body/ballot pool] submitted a ballot.

COMMON ATTRIBUTE 20

Under no circumstances may the board substantively modify the proposed regional reliability standard.

COMMON ATTRIBUTE 21

Once a regional reliability standard is approved by the board, the standard will be submitted to NERC for approval and filing with FERC [and applicable authorities in Canada and Mexico.]

COMMON ATTRIBUTE 22

Open – Participation in the development of a regional reliability standard shall be open to all organizations that are directly and materially affected by the [Regional Entity Name] bulk power system reliability. There shall be no undue financial barriers to participation. Participation shall not be conditioned upon membership in [Regional Entity Name], and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements. Meetings of drafting teams shall be open to the [Regional Entity Name] members and others.

COMMON ATTRIBUTE 23

Balanced – The [Regional Entity Name] standards development process strives to have an appropriate balance of interests and shall not be dominated by any two interest categories and no single interest category shall be able to defeat a matter.

COMMON ATTRIBUTE 24

Inclusive – Any entity (person, organization, company, government agency, individual, etc.) with a direct and material interest in the bulk power system in the [Regional Entity Name] area shall have a right to participate by: a) expressing a position and its basis, b) having that position considered, and c) having the right to appeal.

COMMON ATTRIBUTE 25

Fair due process – The regional reliability standards development procedure shall provide for reasonable notice and opportunity for public comment. At a minimum, the procedure shall include public notice of the intent to develop a standard, a public comment period on the proposed standard, due consideration of those public comments, and a ballot of interested stakeholders.

COMMON ATTRIBUTE 26

- **Transparent** – All actions material to the development of regional reliability standards shall be transparent. All standards development meetings shall be open and publicly noticed on the regional entity's Web site.

COMMON ATTRIBUTE 27

- Does not unnecessarily delay development of the proposed reliability standard.

COMMON ATTRIBUTE 28

Each standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of the reliability of the regional bulk power system. Each standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

COMMON ATTRIBUTE 29

While reliability standards are intended to promote reliability, they must at the same time accommodate competitive electricity markets. Reliability is a necessity for electricity markets, and robust electricity markets can support reliability. Recognizing that bulk power system reliability and electricity markets are inseparable and mutually interdependent, all regional reliability standards shall be consistent with NERC's market interface principles. Consideration of the market interface principles is intended to ensure that standards are written such that they achieve their reliability objective without causing undue restrictions or adverse impacts on competitive electricity markets.

COMMON ATTRIBUTE 30

To ensure uniformity of regional reliability standards, a regional reliability standard shall consist of the elements identified in this section of the procedure. These elements are intended to apply a systematic discipline in the development and revision of standards. This discipline is necessary to achieving standards that are measurable, enforceable, and consistent.

COMMON ATTRIBUTE 31

All mandatory requirements of a regional reliability standard shall be within the standard. Supporting documents to aid in the implementation of a standard may be referenced by the standard but are not part of the standard itself.

COMMON ATTRIBUTE 32

Applicability	Clear identification of the functional classes of entities responsible for complying with the standard, noting any specific additions or exceptions. If not applicable to the entire [Regional Entity Name] area, then a clear identification of the portion of the bulk power system to which the standard applies. Any limitation on the applicability of the standard based on electric facility requirements should be described.

COMMON ATTRIBUTE 33

Measure(s)	Each requirement shall be addressed by one or more measures. Measures are used to assess performance and outcomes for the purpose of determining compliance with the requirements stated above. Each measure will identify to whom the measure applies and the expected level of performance or outcomes required demonstrating compliance. Each measure shall be tangible, practical, and as objective as is practical. It is important to realize that measures are proxies to assess required performance or outcomes. Achieving the measure should be a necessary and sufficient indicator that the requirement was met. Each measure shall clearly refer to the requirement(s) to which it applies.

~~COMMON ATTRIBUTE 34~~

~~Compliance Monitoring Process~~	~~Defines for each measure:~~ • ~~The specific data or information that is required to measure performance or outcomes.~~ • ~~The entity that is responsible for providing the data or information for measuring performance or outcomes.~~ • ~~The process that will be used to evaluate data or information for the purpose of assessing performance or outcomes.~~ • ~~The entity that is responsible for evaluating data or information to assess performance or outcomes.~~ • ~~The time period in which performance or outcomes is measured, evaluated, and then reset.~~ • ~~Measurement data retention requirements and assignment of responsibility for data archiving~~

EXHIBIT D – COMPLIANCE MONITORING AND ENFORCEMENT PROGRAM

1.0 REGIONAL COMPLIANCE MONITORING AND ENFORCEMENT PROGRAM

[REGIONAL ENTITY] will implement the NERC Compliance Monitoring and Enforcement Program, Appendix 4C to the NERC Rules of Procedure (which for purposes of this section 1.0 shall not include Attachment 2, Hearing Procedures), to monitor and enforce compliance with Reliability Standards by the owners, operators, and users within **[REGIONAL ENTITY]'s** geographic or electrical boundaries, and such other scope, set forth on **Exhibit A** of this Agreement.

2.0 REGIONAL HEARING OF COMPLIANCE MATTERS

[REGIONAL ENTITY], to the extent required in the Rules of Procedure, shall establish and maintain a hearing body with authority to conduct and render decisions in compliance hearings in which a Registered Entity may contest a finding of alleged violation, proposed penalty or sanction, or a proposed mitigation plan, which shall be either **[REGIONAL ENTITY]'s** board, ~~or~~ , a committee of the board, a balanced compliance panel reporting directly to **[REGIONAL ENTITY]'s** board or an independent hearing panel. **[REGIONAL ENTITY]'s** hearing body is [its board] [if not the board, insert the name of the committee or group serving as the hearing body].

[If the hearing body is a compliance panel other than the board, provide here a description of how the members of the compliance panel are selected and the qualifications to be selected for the compliance panel.]

To the extent required in the Rules of Procedure, **[REGIONAL ENTITY]** shall conduct all compliance hearings in which a Registered Entity may contest a finding of alleged violation, proposed penalty or sanction, proposed Mitigation Plan, or a proposed Remedial Action Directive, in accordance with Attachment 2, Hearing Procedures, to the NERC Compliance Monitoring and Enforcement Program, subject to the following deviations, if any: [Describe any deviations, or state "None". If there are deviations from the NERC pro forma Hearing Procedures, [REGIONAL ENTITY]'s Hearing Procedures shall be included as a separate attachment to this Exhibit D.]

3.1 OTHER DECISION-MAKING BODIES

If **[*Regional Entity*]** uses other decision-making bodies within its compliance program, provide here a description of the function of that body to the extent not described elsewhere in the Agreement or exhibits, how the members of that body are selected, and the qualifications to be selected for that body.]

Exhibit E — Funding

1. Scope of activities funded through the ERO funding mechanism

[Regional Entity] shall include in its annual budget submission to NERC amounts for costs it will incur in performing its delegated functions and related activities as described in Sections 5, 6 and 7 of the Agreement. These activities shall include:

- Reliability Standard Development
- Compliance Monitoring and Enforcement
- Organization Registration and Certification
- Reliability Assessment and Performance Analysis (including necessary data gathering activities)
- Event Analysis and Reliability Improvement
- Training and Education
- Situation Awareness
- Infrastructure Security

2. Preparation of Annual Business Plan and Budget

(a) NERC and [Regional Entity], in conjunction with the other Regional Entities, shall collaboratively develop an annual schedule for the development, submission, review and approval of [Regional Entity's] business plan and budget. The annual schedule for the preparation of business plans and budgets shall require [Regional Entity] (i) to submit to NERC draft(s) of [Regional Entity]'s proposed business plan and budget and other preliminary documents and information, and (ii) to submit a final proposed business plan and budget that has been approved by [Regional Entity] Board of Trustees to NERC by July 1 or such other agreed date as provides sufficient time for NERC's review, approval and submission of [Regional Entity]'s business plan and budget to the Commission 130 days in advance of the beginning of each fiscal year. The [Regional Entity] business plan and budget submission shall include supporting materials, including [Regional Entity]'s complete business plan and organization chart, explaining the proposed collection of all assessments, dues, fees and charges, and the proposed expenditure of the funds to be collected in sufficient detail to justify the requested budgeted expenditures and assessments. [Regional Entity]'s business plan and budget and proposed assessments shall provide for reasonable reserve mechanisms for unforeseen and extraordinary expenses and other contingencies, consistent with generally accepted accounting principles.

(b) NERC shall review and approve [Regional Entity]'s proposed business plan and budget and proposed assessments for performing the delegated functions and related activities described in Sections 5, 6 and 7 of this Agreement and listed above in Section 1 of this **Exhibit E**, or shall direct [Regional Entity] to make such revisions as NERC deems appropriate prior to approval. NERC shall submit [Regional Entity]'s approved business plan and budget and proposed assessments to the Commission for approval as part of NERC's overall business plan and budget submission, in accordance with the ERO Regulations.

3. Allocation of Costs

Assessments to fund the costs of [REGIONAL ENTITY]'s delegated functions and related activities pursuant to the Agreement shall be allocated among all load-serving entities on the basis of Net Energy for Load, unless a different method(s) of allocating and calculating such assessments has been submitted to and approved by NERC and the Commission in accordance with Section 9(b) of the Agreement. [Regional Entity] shall submit to NERC annually at the same time it submits its budget request a list of the load-serving entities or designees within its geographic boundaries that shall be responsible for paying [Regional Entity's] assessment and the load-serving entities' proportionate Net Energy for Load, and such other data and information as is necessary to allocate and calculate the allocation of [Regional Entity's] assessment to the load-serving entities or designees under the method(s) of allocation and calculation that will be used.

4. Collection of Funding

[IF NERC WILL BILL AND COLLECT ASSESSMENTS DIRECTLY FROM LOAD-SERVING ENTITIES IN REGIONAL ENTITY'S REGION, USE THE FOLLOWING TEXT FOR SECTION 4(a):]

(a) NERC shall submit invoices to the load-serving entities or designees identified by [Regional Entity] covering the NERC and [Regional Entity] assessments approved for collection.

[IF THE REGIONAL ENTITY WILL ACT AS THE BILLING AND COLLECTION AGENT ON BEHALF OF NERC TO BILL AND COLLECT ASSESSMENTS FROM LOAD-SERVING ENTITIES IN REGIONAL ENTITY'S REGION, USE THE FOLLOWING TEXT FOR SECTION 4(a):]

(a) NERC and [Regional Entity] agree that [Regional Entity] shall act as the billing and collection agent on behalf of NERC to bill and collect [Regional Entity]'s assessments from load-serving entities and designees (or such other entities as agreed by NERC and [Regional Entity]). [Regional Entity] agrees that it shall (i) issue all invoices to load-serving entities and other entities in a prompt and timely manner after receipt from NERC of the information needed to issue the invoices; (ii) exercise commercially reasonable efforts to collect invoices that are not paid as of the due date(s); and (iii) transfer all funds collected to NERC in a timely manner, as follows: Prior to the start of each calendar quarter, and once per week thereafter until all billings for the quarter are collected, [Regional Entity] will electronically transfer to NERC, in immediately available funds, all payments received by [Regional Entity] from load-serving entities or other entities for payment of invoices. On the same day that [Regional Entity] makes each electronic transfer of funds to NERC, [Regional Entity] shall send an e-mail to the Chief Financial Officer or Controller of NERC detailing the collections being transmitted, including a listing of the load-serving entities or other entities from which payments were collected and the amount collected from each entity. [Note: If NERC and Regional Entity have a different collection and payment arrangement, the preceding two sentences will be modified accordingly to describe it.]

[Regional Entity] agrees that it shall not in any way use its position as billing and collection agent for NERC to attempt to influence NERC's policies or decisions on matters relating to adoption of Reliability Standards (including Regional Reliability Standards and Regional Variances), administration of the compliance monitoring and enforcement program and other compliance and enforcement matters, determination and imposition of penalties and sanctions, budgeting matters including review and approval of [Regional Entity's] budgets and business plans, or any other NERC decisions, including by issuing invoices, engaging in collection activities or transferring funds collected to NERC in an untimely manner or other than in accordance with this Agreement.

(b) NERC shall pursue any non-payments of assessment amounts and shall request assistance from ~~ERO~~ Applicable Governmental Authorities~~-~~ as necessary to secure collection. To the extent reasonably practicable, [Regional Entity] shall assist NERC in pursuing and collecting any non-payments. Notwithstanding the foregoing, [Regional Entity] is not responsible and does not assume any liability for recovering non-payments or underpayments of assessment amounts. NERC shall retain sole responsibility for recovering non-payments or underpayments of assessment amounts. NERC shall add the amount of any non-payments by end-users or designees within [REGIONAL ENTITY]'s region, that are reasonably determined to be uncollectible, to NERC's assessments for a subsequent year with the amount of such non-payments to be allocated to end-users within [Regional Entity]'s region.

(c) Upon approval by Applicable ~~ERO~~ Governmental Authorities of [Regional Entity]'s annual assessment to fund the costs of its delegated functions and related activities, NERC shall pay [Regional Entity's] annual assessment to Regional Entity in four equal quarterly payments on January 15, April 15, July 15 and October 15 of the budget year.

5. Application of Penalties

Except as otherwise approved by the Commission, all penalty monies received by [Regional Entity], other than penalty monies received from an operational function or division or affiliated entity of [Regional Entity], shall be applied as a general offset to [Regional Entity]'s budget requirements for U.S.-related activities under this Agreement for the subsequent fiscal year. Funds from financial penalties shall not be directly applied to any program maintained by the investigating entity. Except as otherwise approved by the Commission, any penalty monies received from an operational function or division or affiliated entity of [Regional Entity] shall be transmitted to or retained by NERC and shall be used by NERC as a general offset to NERC's budget for its activities as the ERO under the Act for the following year.

6. Budget and Funding for [Regional Entity's] Non-Statutory Activities

In addition to its delegated functions and related activities, as specified in Sections 5, 6 and 7 of the Agreement and in Section 1 of this **Exhibit E** (such delegated functions and activities referred to in this Section 6 as "statutory activities"), [Regional Entity] performs the following other functions and activities (such other functions and activities being

referred to in this Section 6 as "non-statutory activities"): [List and describe all non-statutory activities performed by Regional Entity, or state “None”.]

[Regional Entity] shall employ the following methods and procedures to (i) keep its funding mechanisms for its statutory activities separate from its funding mechanisms for its non-statutory activities, and (ii) record the costs it incurs in the performance of its non-statutory functions separately from the costs it incurs in the performance of its statutory functions: [List and describe the methods and procedures Regional Entity employs to keep costs and funding of statutory activities separate from costs and funding of non-statutory activities, including at a minimum a description of how Regional Entity’s bank accounts and receivables/payables procedures are set up for both statutory and non-statutory functions, a description of how Regional Entity ensures each employee involved in both statutory and non-statutory functions keeps accurate time records reflecting his/her activities, and a description of how Regional Entity’s general and administrative costs are allocated between statutory activities and non-statutory activities. If the necessary descriptions are lengthy they may be provided in a separate attachment labeled “Attachment E-1”, and state here “See Attachment E-1.” If Regional Entity has listed no non-statutory functions in the preceding paragraph, state here “Not applicable.”]

[Regional Entity] shall provide its budget for such non-statutory activities to NERC at the same time that [Regional Entity] submits its proposed annual business plan and budget for statutory activities to NERC pursuant to Section 9 of the Agreement. [Regional Entity's] budget for non-statutory activities that is provided to NERC shall contain a detailed list of [Regional Entity's] non-statutory activities and a description of the funding sources for the non-statutory activities. [Regional Entity] agrees that no costs (which shall include a reasonable allocation of [Regional Entity]’s general and administrative costs) of non-statutory activities are to be included in the calculation of [Regional Entity's] assessments, dues, fees, and other charges for its statutory activities.

7. Amended or Supplemental Business Plans and Budgets

During the course of the fiscal year, if [Regional Entity] determines it does not or will not have sufficient funds to carry out its delegated functions and related activities, [Regional Entity] shall submit to NERC one or more proposed amended or supplemental business plans and budgets and requests for approval of supplemental assessments, reflecting costs, cost increases or funding shortfalls not provided for in [Regional Entity]’s approved business plan and budget for the fiscal year. NERC shall review and approve the proposed amended or supplemental business plan and budget and proposed supplemental assessment, or shall direct [Regional Entity] to make such revisions as NERC deems appropriate prior to approval. NERC shall submit [Regional Entity]’s approved amended or supplemental business plan and budget and proposed supplemental assessment to the Commission for approval.

8. NERC Review of Regional Entity Financial Records

Upon a request made to [Regional Entity] with reasonable notice, NERC shall have access to and may review all financial records of [Regional Entity], including records used to prepare [Regional Entity’s] financial statements. NERC shall conduct reviews of the

quarterly and annual financial statements submitted by [Regional Entity] pursuant to Section 9(h) and (i) of the Agreement. [Regional Entity] shall provide supporting documentation for the quarterly and annual financial statements as reasonably requested by NERC.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Renegotiation of Regional Delegation Agreements Announcement

Notice of Draft Posting: March 2, 2015 – April 2, 2015

Comment Period for Draft Pro Forma Regional Delegation Agreement

In this posting, NERC and the Regional Entities outline their proposed revisions to the pro forma Regional Delegation Agreement (RDA) that, assuming approval by the NERC Board of Trustees, the Regional Entity Boards and the Federal Energy Regulatory Commission (Commission), would be implemented in the eight, individual Regional Entity RDAs. The currently effective RDAs expire on December 31, 2015. With the benefit of several years of operating experience, NERC and the Regional Entities have been working collaboratively since October 2014 to identify opportunities for enhancement and clarification in the currently effective pro forma RDA and to reflect existing oversight and governance practices. The proposed revisions have been endorsed by the ERO Executive Management Group. NERC believes that these revisions will further the efficient operation of the ERO.

The final, renegotiated pro forma RDA, along with updated individual RDAs, will be filed with the Commission, after approval by the NERC Board of Trustees, for approval. NERC and the Regional Entities anticipate making this filing no later than June 2015. After notice and opportunity for comment, the Commission may approve (with or without modifications) or reject the RDAs. Only if the Commission approves the RDAs will they become effective.

Highlights of the Proposed Revisions

Regional Entity Rules

- Streamline the contents of the pro forma RDA by replacing the common attributes for Regional Standard Development Procedures with a reference to the Standard Processes Manual
- Remove the bylaws as well as the Standard Processes Manuals as physical attachments to the individual RDAs to allow these attachments to be amended without requiring refiling of individual RDAs

Compliance Monitoring and Enforcement

- Update provisions to reflect current practices regarding the Compliance Monitoring and Enforcement Programs such as the disposition of instances of noncompliance or penalties as well as the creation of Multi-Regional Registered Entities

Policies and Procedures

- Recognize and enhance NERC's existing ability to collaborate with Regional Entities to develop policies and procedures in the performance of activities related to their Delegated Authority

Regional Entity Performance

- Recognize and enhance NERC's existing ability to periodically review the performance of the Regional Entities' compliance with the RDAs as well as other NERC policies and procedures and to monitor the implementation of guidance and directives issued by NERC

Funding

- Clarify the schedule for the Regional Entities to submit audited financial statements to NERC

Termination

- Provide for an automatic five-year renewal of the RDAs after the expiration of the first five-year term ending in 2020, provided no party provides notice of its intent to terminate no later than one year prior to the then scheduled termination of the RDA

Confidentiality

- Clarify the scope of "Confidential Information," for purposes of the RDAs, to account for proprietary, business sensitive, and critical energy infrastructure information
- Recognize the existing ability of NERC and the Regional Entities to transfer or exchange Confidential Information to enable their respective business units to conduct their delegated activities, thereby streamlining the process for sharing of Confidential Information (which will in all cases continue to be subject to the confidentiality requirements in the NERC Rules of Procedure)

Governing Law

- Amend governing law from New Jersey to Georgia

Submission of Comments

If parties wish to provide comments on the draft RDA, they should do so no later than **Thursday April 2, 2015, and any such comments must be submitted electronically** to RDAComments@nerc.net.

For further information, please contact Nina H. Jenkins-Johnston (via email at nina.johnston@nerc.net) or at (202) 644-8049.

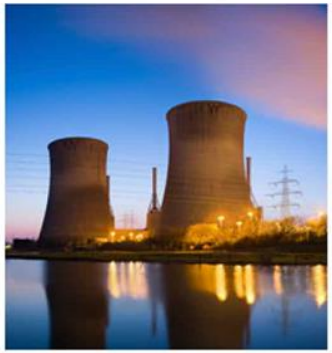
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FAC-003 Research Project

Overview of Validation Testing of Minimum Vegetation Clearance Distances (MVCD)

Robert W. Cummings
Director, Reliability Initiatives and System Analysis
OC & PC Meeting
March 10-11, 2015

RELIABILITY | ACCOUNTABILITY

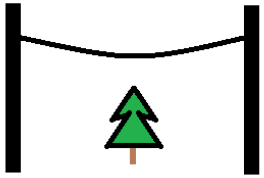





Background

- March 2013 —NERC directed to conduct testing to support appropriate Minimum Vegetation Clearance Distances (MVCD) in FAC-003-3 (Order 777)
- July 2013 — Project plan submitted to FERC
- January 2014 — Advisory team assembled and project initiated
- October 2014 — Planned testing completed by NERC and EPRI

Test Plan

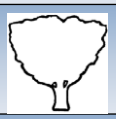
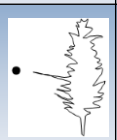
- Selected representative set of vegetation in and around transmission rights-of-way
- Switching impulse tests performed for representative combinations of vegetation shapes and voltages for:
  - Vertical (grow-in) 
  - Horizontal (blow-in) 

Gap Factor Testing Plan

- Switching impulse tests on representative hybrid natural trees fitted with well-grounded metal center rod
  - Vegetation with highest likelihood of flashover
  - Metal rod perturbs electrical field more than vegetation
- Conservatism shown by re-testing of configurations yielding lowest gap factor with wooden dowels replacing metal rods
  - Wooden dowel more closely represents electric field effects of natural vegetation
- Completed final series of withstand tests with fully natural trees without attachments to verify the gap factors determined in the above testing

Preliminary Findings

- Preliminarily testing demonstrated that a gap factor of 1.0 may be more appropriate than the present value of 1.3 contained in FAC-003-3

Test Results for Hybrid Trees with Metal Rod					
Test Configuration	**Tree Shape**	**230 kV**	**345 kV**	**500 kV**	**765 kV**
Vertical/ Grow-in	Trimmed Tree 	***1.15***	1.29	1.16	1.21
	Columnar 	1.19	1.42	1.16	1.24
	Pyramidal 	1.44	1.34	1.27	1.43
Horizontal/ Blow-in	Single Branch 	1.44	1.39	1.35	1.41
	Columnar 	***1.02***	1.17	1.21	1.25

Preliminary Findings

- Comparison of gap factors determined for conductor-to-vegetation gap configuration and system voltage yielding lowest gap factor during metal rod test phase

Test Configuration	Tree Shape	Test Phase	Gap Size	Gap Factor	U_{50}
Horizontal/ Blow-in	Columnar	Metal Rod	38.6”	1.02	379 kV
		Wooden Dowel	38.6”	1.22	451 kV
		Tree Only	38.6”	1.23	459 kV

MVCD Comparison

- Existing FAC-003-3 gap factor of 1.3 versus preliminarily determined gap factor of 1.0
- Shows increase in MVCD of ½ foot to 3½ feet with 1.0 gap factor (230 kV and above)

MVCD Comparison at Sea Level			
Nominal System Voltage (kV)	**MVCD @ 1.3 (ft)**	**MVCD @ 1.0 (ft)**	**Increase in MVCD (ft)**
765	8.20	11.63	3.43
500	5.15	7.04	1.89
345	3.19	4.25	1.06
230	3.03	4.03	1.00

Going Forward

- June 2015 — File final NERC report with FERC
- NERC may use other communication tools to socialize the conclusions developed after testing
- Likely a narrowly defined Standard Authorization Request will be needed to adjust MVCD values in FAC-003-3

Considerations

- Applicable Transmission Owners and Generator Owners may consider adjusting MVCDs prior to Spring maintenance

Nominal AC System Voltage (kV)	MVCD at 1.0 Gap Factor (ft)											
	Sea Level up to 500 ft	Over 500 ft up to 1,000 ft	Over 1,000 ft up to 2,000 ft	Over 2,000 ft up to 3,000 ft	Over 3,000 ft up to 4,000 ft	Over 4,000 ft up to 5,000 ft	Over 5,000 ft up to 6,000 ft	Over 6,000 ft up to 7,000 ft	Over 7,000 ft up to 8,000 ft	Over 8,000 ft up to 9,000 ft	Over 9,000 ft up to 10,000 ft	Over 10,000 ft up to 11,000 ft
765	11.63	11.68	11.90	12.07	12.24	12.42	12.61	12.8	13.00	13.14	13.34	13.49
500	7.04	7.08	7.24	7.37	7.50	7.63	7.77	7.92	8.07	8.17	8.34	8.45
345	4.25	4.28	4.39	4.48	4.57	4.66	4.76	4.87	4.97	5.05	5.17	5.25
287	5.23	5.26	5.39	5.49	5.60	5.71	5.82	5.94	6.07	6.15	6.29	6.39
230	4.03	4.06	4.16	4.25	4.33	4.43	4.52	4.62	4.73	4.80	4.91	4.99
161	2.69	2.71	2.79	2.85	2.91	2.98	3.04	3.12	3.20	3.25	3.33	3.39
138	2.28	2.29	2.36	2.41	2.47	2.52	2.58	2.65	2.71	2.76	2.83	2.88
115	1.87	1.89	1.94	1.99	2.03	2.08	2.13	2.19	2.24	2.28	2.34	2.39
88	1.53	1.54	1.59	1.62	1.66	1.70	1.75	1.79	1.84	1.87	1.92	1.96
69	1.08	1.09	1.13	1.15	1.18	1.21	1.24	1.27	1.31	1.33	1.37	1.40

Contact Information

Neil Burbure

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neil.burbure@nerc.net

Testing





Questions and Answers

New Power Authority Comments on CIP-002-5.1: Identification of BES Cyber Systems at Control Centers Pursuant to Reliability Standard CIP-002-5.1 Lessons Learned

NERC Guidance

"Under this definition, Control Centers are not limited to facilities owned or operated by specific functional entities (i.e., a Reliability Coordinator, Balancing Authority, Transmission Operator, or Generator Operator). Rather, a Control Center is a facility where any functional entity hosts personnel that 'monitor and control the Bulk Electric System (BES) in real-time *to perform the reliability tasks*…of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.' Accordingly, whether a responsible entity has a Control Center, as defined in the NERC Glossary, is not dependent on the entity's Functional Registration (i.e., the functional entity or entities for which it is registered on NERC's Compliance Registry) but on the reliability tasks performed by its personnel. Any functional entity, including Transmission Owners or Generation Owners, may own or operate a Control Center."

Entity Response

NERC's interpretation that a Control Center encompasses any control room that merely hosts personnel that could respond to the directives of a RC, BA, TOP or GOP and that all cyber assets in these control rooms are High Impact is an overly broad interpretation. This interpretation is contrary to the plain meaning of the NERC CIP standards and the long-standing role of NERC's Functional Model, *NERC Reliability Functional Model version 5* ("Functional Model"), and registration process, defined in the NERC Rules of Procedure and Statement of Compliance Registry Criteria ("SCRC"), in determining entity registration and subsequent compliance obligations. It erases the dividing line between what is High impact and what is not and creates uncertainty in the NERC compliance and enforcement processes.

Guidance provided in CIP-002-5.1, Guidelines and Technical Basis, Attachment 1, is clear on the two ways an entity will be considered to perform the functions that would classify them as a Control Center: 1) that the entity is registered in accordance with the Functional Model definition as RC, BA, TOP or GOP; or 2) if there is an agreement that the entity will perform the functions of these entities.

> "This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model . . . ."
> * * *
> While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact."
> * * *
> "A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center." (*emphasis added*)

Classifying an entity's assets in contradiction to its registration status determined consistent with the Functional Model, absent and agreement to accept such functional responsibilities, is an end run around the registration process and will extend the scope of compliance standards to entities' assets that should more correctly be classified as Medium or Low. Furthermore, introducing the subjective element of determining whether personnel perform reliability tasks will erode compliance and enforcement clarity that presently exists under the Functional Model and registration process.

Moreover, NERC concurs in its Lessons Learned guidance, page 2, that the Functional Model states that TOs do not do perform any real time functions.

> "In the context of NERC's Reliability Standards, the functional obligations refer to tasks and relationships outlined in the NERC Functional Model (Version 5).[1] In the specific case of the relationship between a Transmission Owner and a Transmission Operator, the NERC Functional Model does not describe any real-time or operational tasks or relationships to be performed by the Transmission Owner function; rather, all real-time tasks and relationships are performed by the Transmission Operator function." (*emphasis added*)

This statement contradicts NERC's conclusion that: "if a Transmission Owner operates a SCADA system or any field devices (breakers, switches, etc.), it is considered "performing the functional obligations of the Transmission Operator . . . ." If NERC wishes to alter the content of the Functional Model it should propose such changes through the proper processes, not through an informational document.

The criteria enumerated in the SCRC and the NERC Functional Model has been consistently applied to determine entity registration since June 2007. The subjective interpretation proposed by NERC would treat entities as TOP and GOP for CIP functions where they are not presently registered as such. At best, this creates a paradox where an entity not registered as TOP or GOP for operations and planning functions is nonetheless considered a TOP or GOP for CIP functions. At worst, this begins the slippery slope towards reclassifying entities for operations and planning functions in the same manner they are treated for CIP functions.

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Reliability Standard Audit Worksheet[1]

PRC-004-5 – Protection System Misoperation Identification and Correction

This section to be completed by the Compliance Enforcement Authority.

Audit ID:	Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity:	Registered name of entity being audited
NCR Number:	NCRnnnnn
Compliance Enforcement Authority:	Region or NERC performing audit
Compliance Assessment Date(s):[2]	Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method:	Audit
Names of Auditors:	Supplied by CEA

Applicability of Requirements

	BA	DP	GO	GOP	IA	LSE	PA	PSE	RC	RP	RSG	TO	TOP	TP	TSP
R1		X	X									X			
R2		X	X									X			
R3		X	X									X			
R4		X	X									X			
R5		X	X									X			
R6		X	X									X			

[1] NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The NERC RSAW language contained within this document provides a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserves the right to request additional evidence from the registered entity that is not included in this RSAW. Additionally, this RSAW includes excerpts from FERC Orders and other regulatory references. The FERC Order cites are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

Facilities

4.2.1 Protection Systems for BES Elements, with the following exclusions:

4.2.1.1 Non-protective functions that are embedded within a Protection System.

4.2.1.2 Protective functions intended to operate as a control function during switching.[3]

4.2.1.3 Special Protection Systems (SPS).

4.2.1.4 Remedial Action Schemes (RAS).

4.2.1.5 Protection Systems of individual dispersed power producing resources identified under Inclusion I4 of the BES definition where the Misoperations affected an aggregate nameplate rating of less than or equal to 75 MVA of BES Facilities.

4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

4.2.3 Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

Subject Matter Experts

Identify Subject Matter Expert(s) responsible for this Reliability Standard. (Insert additional rows if necessary)

Registered Entity Response (Required):

SME Name	Title	Organization	Requirement(s)

[3] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

R1 Supporting Evidence and Documentation

R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation under the following circumstances:

1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and

1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and

1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified the Misoperation of its Protection System component(s), if any, that meet the circumstances in Requirement R1, Parts 1.1, 1.2, and 1.3 within the allotted time period. Acceptable evidence for Requirement R1, including Parts 1.1, 1.2, and 1.3 may include, but is not limited to, the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance. Please contact your CEA with any questions regarding requested evidence.
A list of BES interrupting device operations within the audit period meeting the criteria of Requirement R1 Parts 1.1 through 1.3.
Of these BES interrupting device operations, evidence such as in Measure M1 identifying whether its Protection System component(s) caused a Misoperation (or not).

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to PRC-004-5, R1

This section to be completed by the Compliance Enforcement Authority

	Select, all or a sample thereof, BES interrupting device operations meeting the criteria of Requirement R1 Part 1.1 through 1.3 from the list of such operations outlined in the Evidence Requested section above.
	For selected BES interrupting device operations meeting the criteria of Requirement R1 Part 1.1 through 1.3, verify the entity identified whether or not its Protection System component(s) caused a Misoperation within 120 calendar days of the BES interrupting device operation.

Note to Auditor: Auditors should use their professional judgment in selecting BES interrupting device operations for testing. Sources of such operations could include entity lists or auditor's knowledge of events occurring on the entity's system. In order to determine if the entity identified whether there was a Misoperation (in accordance with Requirement R1) the auditor should seek evidence, such as that provided in Measure M1, associated with analyses of those BES interrupting device operations meeting Requirement R1, Parts 1.1 through 1.3.

If the BES interrupting device operation does not meet the criteria, then no identification is necessary and no further audit testing is required.

Auditor may identify instances where an entity identified a Misoperation of its Protection System component(s), but did not determine the cause(s) of the Misoperation (within the 120 calendar day period of R1) for verification of compliance with Requirement R4.

Auditor Notes:

R2 Supporting Evidence and Documentation

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in 2.1 and 2.2:

2.1 For a BES interrupting device operation by a Composite Protection System, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances:

2.1.1 The BES interrupting device owner shares the Composite Protection System ownership with any other owner; and

2.1.2 The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and

2.1.3 The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.

2.2 For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates notification to the other owner(s), within the allotted time period for either Requirement R2, Part 2.1, including subparts 2.1.1, 2.1.2, and 2.1.3 and Requirement R2, Part 2.2**.**Acceptable evidence for Requirement R2, including Parts 2.1, and 2.2 may include, but is not limited to, the following dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance. Please contact your CEA with any questions regarding requested evidence.
A list of BES interrupting device operations within the audit period meeting the criteria of Part 2.1, Parts 2.1.1 through 2.1.3.
For Requirement R2 Part 2.2, a list of BES interrupting device operations within the audit period that operated as backup protection for a condition on another entity's Element.
Of these BES interrupting device operations, evidence such as in Measure M2 of entity notifying other owner(s) of the Composite Protection System.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to PRC-004-5, R2

This section to be completed by the Compliance Enforcement Authority

	Select, all or a sample thereof, BES interrupting device operations meeting Requirement R2, Parts 2.1 and 2.2.
	For selected BES interrupting device operations requiring notifying other owner(s), verify the entity notified the other owners of the operation within 120 days of the operation.
Note to Auditor: Auditors should use their professional judgment in selecting BES interrupting device operations for testing. Sources of such operations could include entity lists or auditor's knowledge of events occurring on the entity's system. In order to determine if the entity notified other owners of the Composite Protection System (in accordance with Requirement R2) auditor should seek evidence, as provided in Measure M2 associated with selected operations. See Application Guidelines under section Requirement R2 for notification requirements for vertically integrated utilities.	

Auditor Notes:

R3 Supporting Evidence and Documentation

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation.

M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified whether its Protection System component(s) caused a Misoperation within the allotted time period. Acceptable evidence for Requirement R3 may include, but is not limited to, the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance. Please contact your CEA with any questions regarding requested evidence.
List of notifications received by entity within the audit period pursuant to Requirement R2.
Of these notifications, evidence such as in Measure M3 of the entity identifying whether its Protection System component(s) caused a Misoperation (or not).

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to PRC-004-5, R3

This section to be completed by the Compliance Enforcement Authority

	Select, all or a sample thereof, notifications received by entity pursuant to Requirement R2.

	For notifications received by entity, as selected by auditor, verify entity identified, within the timeframes established in Requirement R3, whether its Protection System component(s) caused a Misoperation.

Note to Auditor: Auditors should use their professional judgment in selecting notifications for audit testing. Sources of such notifications could include entity lists, auditor's knowledge of events occurring on the entity's system, or inquiries of neighboring entities. In order to determine if entity identified whether its Protection System component(s) caused a Misoperation, the auditor should seek evidence, as provided in Measure M3, associated with selected notifications.

Auditor may identify instances where an entity identified a Misoperation of its Protection System component(s) (in accordance with Requirement R3), but did not determine the cause(s) of the Misoperation for verification of compliance with Requirement R4.

Auditor Notes:

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R4 Supporting Evidence and Documentation

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3 shall perform investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation:

- The identification of the cause(s) of the Misoperation; or
- A declaration that no cause was identified.

M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it performed at least one investigative action according to Requirement R4 every two full calendar quarters until a cause is identified or a declaration is made. Acceptable evidence for Requirement R4 may include, but is not limited to, the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance. Please contact your CEA with any questions regarding requested evidence.
List of identified Misoperations pursuant to Requirement R1 or R3, within the audit period, where the cause of the Misoperation was not revealed.
Of the Misoperation list, documented cause(s) of the Misoperation pursuant to Requirement R4.
Of the Misoperation list, declarations where no cause was identified.
Evidence such as in Measure M4.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to PRC-004-5, R4

This section to be completed by the Compliance Enforcement Authority

	Select, all or a sample of, identified Misoperations where a cause has not been identified by the entity.
	For each identified Misoperation without a cause selected, verify entity performed (or is performing) investigative action(s) to determine the cause(s) of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified.
	For completed investigative actions, verify that entity has either determined a cause or has a declaration that no cause was identified.

Note to Auditor: Auditors should use their professional judgment in selecting Misoperations for audit testing. Sources of such Misoperations could include entity lists or knowledge gained by the auditor via their review of Requirements R1 or R3. In order to determine if entity performed the investigative action(s) established in Requirement R4, the auditor should seek evidence, as provided in Measure M4, associated with selected Misoperations.

The following is an example of what is meant by "once every two full calendar quarters after the Misoperation was first identified:" A Misoperation (with no cause) initially identified on February 10 (Quarter One) must be investigated (per Requirement R4) by September 30 (Quarter three) of the same year. Quarters two and three are the full quarters counted.

Auditor Notes:

R5 Supporting Evidence and Documentation

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation:

- Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations, or
- Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it developed a CAP and an evaluation of the CAP's applicability to other Protection Systems and locations, or a declaration in accordance with Requirement R5. Acceptable evidence for Requirement R5 may include, but is not limited to the following dated documentation (electronic or hardcopy format): CAP and evaluation, or declaration.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance. Please contact your CEA with any questions regarding requested evidence.
Within the audit period, evidence such as in Measure M5 for Misoperations with an identified cause.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to PRC-004-5, R5

This section to be completed by the Compliance Enforcement Authority

	Select, all or a sample thereof, identified Misoperations with a cause.
	For identified Misoperations with a cause, as selected by the auditor, verify entity developed a CAP and evaluation, or a declaration as described in Requirement R5.
	Verify CAP and evaluation, or declaration, was developed within 60 calendar days of the first identified cause.
	Verify CAP contains actions and a timetable to resolve the cause(s) of the identified Misoperation and verify entity evaluated the CAP's applicability to the entity's other Protection Systems and locations; or that the declaration contains why no corrective action will be taken according to Requirement R5.
Note to Auditor: Auditors should use their professional judgment in selecting Misoperations with an identified cause for audit testing. Sources of such Misoperations for audit testing should be obtained from information learned by, or provided to, the auditor from testing of Misoperations for Requirements R1, R3, or R4.	

Auditor Notes:

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R6 Supporting Evidence and Documentation

R6. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed.

M6. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables. Acceptable evidence for Requirement R6 may include, but is not limited to the following dated documentation (electronic or hard copy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance. Please contact your CEA with any questions regarding requested evidence.
From the CAPs developed in Requirement R5, evidence such as in Measure M6 demonstrating implementation of each CAP.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to PRC-005-3, R6

This section to be completed by the Compliance Enforcement Authority

	Select, all or a sample thereof, CAPs for correcting the cause(s) of an identified Misoperation.
	For CAPs selected, verify implementation and that CAP was updated in accordance with Requirement R6.

Note to Auditor: Auditors should use their professional judgment in selecting CAPs for audit testing. Sources of CAPs for audit testing should be obtained from information learned by, or provided to, the auditor in Requirement R5.

In checking for implementation, auditors should verify evidence (such as described in Measure M6) that the actions or activities prescribed by the CAP were actually performed by the entity.

Items, such as work management records, supporting the implementation of actions and timetables to implement the CAP are alternatives to a written document.

Auditor Notes:

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Additional Information:

Reliability Standard

The full text of PRC-004-5 may be found on the NERC website (www.nerc.com) under "Program Areas & Departments", "Reliability Standards."

In addition to the Reliability Standard, there is an applicable Implementation Plan available on the NERC website.

In addition to the Reliability Standard, there is background information available on the NERC website.

Capitalized terms in the Reliability Standard refer to terms in the *Glossary of Terms Used in NERC Reliability Standards*, which may be found on the NERC website.

Sampling Methodology

Sampling is essential for auditing compliance with NERC Reliability Standards since it is not always possible or practical to test 100% of either the equipment, documentation, or both, associated with the full suite of enforceable standards. The Sampling Methodology Guidelines and Criteria, or sample guidelines, provided by the Electric Reliability Organization help to establish a minimum sample set for monitoring and enforcement uses in audits of NERC Reliability Standards.

Regulatory Language [Developer to ensure RSAW has been provided to NERC Legal for links to appropriate Regulatory Language – See example below]

E.g. FERC Order No. 742 paragraph 34: "Based on NERC's……."

E.g. FERC Order No. 742 Paragraph 55, Commission Determination: "We affirm NERC's……."

Selected Glossary Terms

The following Glossary terms are provided for convenience only. Please refer to the NERC web site for the current enforceable terms.

- Composite Protection System
- Corrective Action Plan (CAP)
- Misoperation
- Protection System

Revision History

Version	Date	Reviewers	Revision Description
1	2/19/2015	NERC Compliance	New Document for PRC-004-5 based on version of RSAW posted for PRC-004-3.

[i] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Standard Audit Worksheet[1]

PRC-010-2 – Undervoltage Load Shedding

This section to be completed by the Compliance Enforcement Authority.

Audit ID:	Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity:	Registered name of entity being audited
NCR Number:	NCRnnnnn
Compliance Enforcement Authority:	Region or NERC performing audit
Compliance Assessment Date(s)[2]:	Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method:	[On-site Audit | Off-site Audit | Spot Check]
Names of Auditors:	Supplied by CEA

Applicability of Requirements

	BA	DP	GO	GOP	IA	LSE	PA	PSE	RC	RP	RSG	TO	TOP	TP	TSP
R1							X							X	
R2		X[3]										X[3]			
R3							X							X	
R4							X							X	
R5							X							X	
R6							X								
R7		X[3]										X[3]			
R8							X								

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[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

[3] Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of undervoltage Load shedding (UVLS) equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator.

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Legend:

Text with blue background:	Fixed text – do not edit
Text entry area with Green background:	Entity-supplied information
Text entry area with white background:	Auditor-supplied information

DRAFT

Findings

(This section to be completed by the Compliance Enforcement Authority)

Req.	Finding	Summary and Documentation	Functions Monitored
R1			
R2			
R3			
R4			
R5			
R6			
R7			
R8			

Req.	Areas of Concern

Req.	Recommendations

Req.	Positive Observations

DRAFT

Subject Matter Experts

Identify the Subject Matter Expert(s) responsible for this Reliability Standard.

Registered Entity Response (Required; insert additional rows if needed):

SME Name	Title	Organization	Requirement(s)

DRAFT

R1 Supporting Evidence and Documentation

R1. Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS Program. The evaluation shall include, but is not limited to, studies and analyses that show:

1.1. The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design.

1.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, auto-reclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M1. Acceptable evidence may include, but is not limited to, date-stamped studies and analyses, reports, or other documentation detailing the effectiveness of the UVLS Program, and date-stamped communications showing that the UVLS Program specifications and implementation schedule were provided to UVLS entities.

Registered Entity Response (Required):
Question:
Have you completed development of a UVLS Program during the audit period? ☐ Yes ☐ No

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
(R1) Provide date-stamped documentation showing that there was an evaluation of the UVLS Program's effectiveness per Parts 1.1 and 1.2 prior to providing the ULVS Program specifications and implementation schedule to UVLS entities.
(R1) Provide date-stamped communications showing the UVLS Program specifications and implementation schedule were provided to UVLS entities.
(Part 1.1) Provide date-stamped documentation that evaluates whether the implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design.
(Part 1.2) Provide date-stamped documentation that evaluates whether the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control

systems, including, but not limited to, transmission line protection, auto-reclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to PRC-010-2, R1

This section to be completed by the Compliance Enforcement Authority

	(R1) Review date-stamped documentation to validate that the Planning Coordinator or Transmission Planner that has developed a UVLS Program during the audit period has evaluated its effectiveness per Parts 1.1 and 1.2 prior to providing the ULVS Program specifications and implementation schedule to UVLS entities.
	(R1) Review date-stamped communications to validate the UVLS Program specifications and implementation schedule were provided to UVLS entities. Specifications may include voltage set points, time delays, amount of load to be shed, the location at which load needs to be shed, etc.
	(Part 1.1) Review date-stamped documentation to validate an evaluation was completed that shows the UVLS Program resolves the identified undervoltage issues that led to its development and design.
	(Part 1.2) Review date-stamped documentation to validate an evaluation was completed that shows the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, auto-reclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.
Note to Auditor: Requirement R1 is applicable only to Planning Coordinators or Transmission Planners that have completed development of a UVLS Program during the audit period; existing UVLS Programs (developed either prior to the audit period or prior to the effective date of PRC-010-2) are covered in Requirement R3.	

A UVLS Program must mitigate risk of one more of the following: voltage instability, voltage collapse, or Cascading **impacting the BES**, and **not** undervoltage-based load shedding installed to mitigate damage to equipment or local loads that are directly affected by the low-voltage event. Centrally controlled undervoltage-based load shedding is also not considered a UVLS Program as it falls under the NERC Glossary definition of a Remedial Action Scheme.

Auditor Notes:

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R2 Supporting Evidence and Documentation

R2. Each UVLS entity shall adhere to the UVLS Program specifications and implementation schedule determined by its Planning Coordinator or Transmission Planner associated with UVLS Program development per Requirement R1 or with any Corrective Action Plans per Requirement R5.

M2. Acceptable evidence must include date-stamped documentation on the completion of actions and may include, but is not limited to, identifying the equipment armed with UVLS relays, the UVLS relay settings, associated Load summaries, work management program records, work orders, and maintenance records.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance.
(R2) Provide the date-stamped implementation schedule for a UVLS Program provided by the Planning Coordinator or Transmission Planner.
(R2) Provide date-stamped documentation demonstrating all necessary actions were completed to implement the UVLS Program.
(R2) Provide a date-stamped list of all Corrective Action Plans (CAPs) provided by the Planning Coordinator or Transmission Planner.
(R2) Provide date-stamped documentation demonstrating all necessary actions were completed to implement each CAP.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to PRC-010-2, R2

This section to be completed by the Compliance Enforcement Authority

	(R2) Review date-stamped documentation to validate all necessary actions were completed by the UVLS entity to implement a UVLS Program.
	(R2) For each CAP listed, review date-stamped documentation to validate all necessary actions were completed by the UVLS entity to implement the CAP.
Note to Auditor: Depending on the planning and documentation format used by the responsible entity, evidence of a successful execution could consist of signed-off work orders, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, paid invoices, photographs, walk-through reports, or other evidence. See the Guidelines and Technical Basis section of the standard, specifically the Guidelines for Requirement R2, for documentation examples.	

Auditor Notes:

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R3 Supporting Evidence and Documentation

R3. Each Planning Coordinator or Transmission Planner shall perform a comprehensive assessment to evaluate the effectiveness of each of its UVLS Programs at least once every 60 calendar months. Each assessment shall include, but is not limited to, studies and analyses that evaluate whether:

3.1. The UVLS Program resolves the identified undervoltage issues for which the UVLS Program is designed.

3.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, auto-reclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M3. Acceptable evidence must include date-stamped documentation on the completion of actions and may include, but is not limited to, identifying the equipment armed with UVLS relays, the UVLS relay settings, associated Load summaries, work management program records, work orders, and maintenance records.

Registered Entity Response (Required):
Question:
Have you had a UVLS Program for more than 60 calendar months? ☐ Yes ☐ No

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance.
(R3) Provide date-stamped documentation demonstrating performance of a comprehensive assessment to evaluate the UVLS Program's effectiveness per Parts 3.1 and 3.2 at least once every 60 calendar months.
(Part 3.1) Provide date-stamped documentation demonstrating each assessment included studies and analyses that evaluate whether the UVLS Program resolves the identified undervoltage issues for which the UVLS Program is designed.
(Part 3.2) Provide date-stamped documentation demonstrating each assessment included studies and analyses that evaluate whether the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, auto-reclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to PRC-010-2, R3

This section to be completed by the Compliance Enforcement Authority

	(R3) Review date-stamped documentation to validate a comprehensive assessment to evaluate the UVLS Program's effectiveness per Parts 3.1 and 3.2 was performed at least once every 60 calendar months.
	(Part 3.1) Review date-stamped documentation to validate each assessment included studies and analyses that evaluate whether the UVLS Program resolves the identified undervoltage issues for which the UVLS Program is designed.
	(Part 3.2) Review date-stamped documentation to validate if each assessment included studies and analyses that evaluate whether the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, auto-reclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.
Note to Auditor: The 60-calendar-month cycle is based on when a UVLS Program was established and not when PRC-010-2 became effective. If a comprehensive assessment is performed sooner than 60 calendar months due to material changes to system topology or operating conditions, the 60-calendar-month time period would restart upon completion of that assessment.	

Auditor Notes:

R4 Supporting Evidence and Documentation

R4. Each Planning Coordinator or Transmission Planner shall, within 12 calendar months of an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, perform an assessment to evaluate:

4.1. Whether its UVLS Program resolved the undervoltage issues associated with the event, and

4.2. The performance (i.e., operation and non-operation) of the UVLS Program equipment.

M4. Acceptable evidence may include, but is not limited to, date-stamped event data, event analysis reports, or other documentation detailing the assessment of the UVLS Program and associated equipment.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance.
(R4) Provide a list of all events that resulted in a voltage excursion for which the UVLS Program was designed to operate.
(R4) Provide date-stamped documentation demonstrating an assessment was performed within 12 calendar months of each event that resulted in a voltage excursion for which the UVLS Program was designed to operate. Include a copy of the assessment used to evaluate whether the UVLS Program resolved the undervoltage issues and the performance of the UVLS Program equipment associated with the event.
(Part 4.1) Provide date-stamped documentation demonstrating an assessment evaluated whether the UVLS Program resolved the undervoltage issues associated with the event.
(Part 4.2) Provide date-stamped documentation demonstrating an assessment evaluated the performance of the UVLS Program equipment associated with the event.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to PRC-010-2, R4

This section to be completed by the Compliance Enforcement Authority

	(R4) For each event listed, review the date-stamped documentation to validate an assessment was performed within 12 calendar months of the event.
	(Part 4.1) For each event listed, review the date-stamped documentation to validate that the assessment evaluated whether the UVLS Program resolved the undervoltage issues associated with the event.
	(Part 4.2) For each event listed, review the date-stamped documentation to validate that the assessment evaluated performance (i.e., operation and non-operation) of the UVLS Program equipment associated with the event.

Note to Auditor: It is expected that an assessment would include event data analysis, such as the relevant sequence of events leading to the undervoltage conditions (e.g., Contingencies, operation of protection systems, and Remedial Action Scheme) and field measurements useful to analyzing the behavior of the system.

A comprehensive description of the UVLS Program operation should be presented, including conditions of the trigger (e.g., voltage levels, time delays) and amount of load shed for each affected substation.

Simulations of the event should have been performed to evaluate the level of performance of the UVLS Program for the event of interest and to identify deficiencies to be included in a Corrective Action Plan (CAP) per Requirement R5.

The studies and analyses showing the effectiveness of the UVLS Program can be similar to what is required in Requirements R1 and R3, but should include a clear link between the evaluation of effectiveness (in studies using simulations) and the analysis of the event (with measurements and event data) that actually occurred.

Auditor Notes:

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R5 Supporting Evidence and Documentation

R5. Each Planning Coordinator or Transmission Planner that identifies deficiencies during an assessment performed in either Requirement R3 or R4 shall develop a Corrective Action Plan to address the deficiencies and subsequently provide the Corrective Action Plan, including an implementation schedule, to UVLS entities within three calendar months of completing the assessment.

M5. Acceptable evidence must include a date-stamped Corrective Action Plan that addresses identified deficiencies and may also include date-stamped reports or other documentation supporting the Corrective Action Plan. Evidence should also include date-stamped communications showing that the Corrective Action Plan and an associated implementation schedule were provided to UVLS entities.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance.
(R5) Provide a date-stamped list of all UVLS Program deficiencies identified during any assessments performed in either Requirement R3 or R4.
(R5) For each assessment that identified UVLS Program deficiencies, provide date-stamped documentation that demonstrates that a Corrective Action Plan (CAP), including an implementation schedule, was provided to UVLS entities within three calendar months of completing each assessment.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to PRC-010-2, R5

This section to be completed by the Compliance Enforcement Authority

	(R5) Review the date-stamped documentation to validate UVLS Program deficiencies identified in any assessments performed in either Requirement R3 or R4 were addressed in a CAP.
	(R5) Review the date-stamped documentation to validate that each CAP, including an implementation schedule, was provided to UVLS entities within three calendar months of completing the assessment.
Note to Auditor: The "within three calendar months" time frame is solely to develop a CAP, including its implementation schedule, and provide it to UVLS entities. It does not include the time needed for its implementation by UVLS entities. This implementation time frame is dictated within the CAP's associated timetable for implementation, and the execution of the CAP according to its schedule is required in Requirement R2.	

Auditor Notes:

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R6 Supporting Evidence and Documentation

R6. Each Planning Coordinator that has a UVLS Program in its area shall update a database containing data necessary to model its UVLS Program for use in event analyses and assessments of the UVLS Program at least once each calendar year.

M6. Acceptable evidence may include, but is not limited to, date-stamped spreadsheets, database reports, or other documentation demonstrating a UVLS Program database was updated.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance.
(R6) Provide date-stamped documentation that demonstrates a database containing data necessary to model an entity's UVLS Program for use in event analyses and assessments of the UVLS Program was updated at least once each calendar year.
(R6) Provide a date-stamped list of all data fields contained in the UVLS Program database.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to PRC-010-2, R6

This section to be completed by the Compliance Enforcement Authority

	(R6) Review the date-stamped documentation to validate a database containing data necessary to model the UVLS Program for use in event analyses and assessments of the UVLS Program was updated at least once each calendar year.
	(R6) Review the date-stamped documentation to validate the database includes the following items: • Owner and operator of the UVLS Program • Size and location of customer load, or percent of connected load, to be interrupted • Corresponding voltage set points and clearing times • Time delay from initiation to trip signal • Breaker operating times • Any other schemes that are part of or impact the UVLS Programs, such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS, and RAS
Note to Auditor: See the Guidelines and Technical Basis section of the standard, specifically the guidelines for Requirement R6.	

Auditor Notes:

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R7 Supporting Evidence and Documentation

R7. Each UVLS entity shall provide data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of a UVLS Program database.

M7. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating data was provided to the Planning Coordinator as specified.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance.
(R7) Provide date-stamped documentation that demonstrates the format and schedule specified by the Planning Coordinator to support maintenance of a UVLS Program database.
(R7) Provide date-stamped documentation that demonstrates data was provided to the Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of a UVLS Program database.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to PRC-010-2, R7

This section to be completed by the Compliance Enforcement Authority

	(R7) Review the date-stamped documentation to validate the format and schedule specified by the Planning Coordinator to support maintenance of a UVLS Program database.
	(R7) Review the date-stamped documentation to validate the UVLS entity provided data to the Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of a UVLS Program database.
Note to Auditor: The intent is for UVLS entities to review the data annually and provide changes to the Planning Coordinators so that Planning Coordinators can keep the databases current and accurate for performing event analysis and other assessments.	

Auditor Notes:

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R8 Supporting Evidence and Documentation

R8. Each Planning Coordinator that has a UVLS Program in its area shall provide its UVLS Program database to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of a written request.

M8. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating that the UVLS Program database was provided within 30 calendar days of receipt of a written request.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance.
(R8) Provide date-stamped documentation that demonstrates all written requests received.
(R8) Provide date-stamped documentation that demonstrates you provided your UVLS Program database within 30 calendar days of all written requests.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to PRC-010-2, R8

This section to be completed by the Compliance Enforcement Authority

	(R8) Review the date-stamped documentation to validate written requests have been received.
	(R8) Review the date-stamped documentation to validate the Planning Coordinator provided the UVLS Program database within 30 calendar days of written requests.
Note to Auditor: Requirement R8 only applies if a **written** request is received.	

Auditor Notes:

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Additional Information:

Reliability Standard

The full text of PRC-010-2 may be found on the NERC Web Site (www.nerc.com) under "Program Areas & Departments", "Reliability Standards."

In addition to the Reliability Standard, there is an applicable Implementation Plan available on the NERC Web Site.

In addition to the Reliability Standard, there is background information available on the NERC Web Site.

Capitalized terms in the Reliability Standard refer to terms in the NERC Glossary, which may be found on the NERC Web Site. See the *Selected Glossary Terms* section below for the approved definition of *Undervoltage Load Shedding Program*.

Regulatory Language

[Placeholder for language from FERC Order approving PRC-010-2]

Selected Glossary Terms

The following Glossary terms are provided for convenience only. Please refer to the NERC web site for the current enforceable terms.

Undervoltage Load Shedding Program (UVLS Program): An automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions leading to voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System (BES). Centrally-controlled undervoltage-based load shedding is not included.

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Rationale for Definition: As part of the development of PRC-010-2, the drafting team found it necessary to introduce the term Undervoltage Load Shedding Program (UVLS Program) to establish PRC-010-2's applicability. The following are critical defining elements of the proposed term:
1) The definition provides flexibility for the Planning Coordinator or Transmission Planner to determine if a UVLS system falls under the defined term with respect to the impact on the reliability of the BES. (See Guidelines and Technical Basis section for further discussion.)

2) Centrally-controlled undervoltage-based load shedding is excluded because its design and characteristics are commensurate with a Special Protection Systems (SPS) or Remedial Action Scheme (RAS) (wherein load shedding is the remedial action). As such, centrally-controlled undervoltage-based load shedding should be subject to SPS/RAS-related Reliability Standards. (See Guidelines and Technical Basis section for rationale.)

Consequently, the drafting team has recommended that Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems) include centrally-controlled undervoltage-based load shedding in the definition of a Special Protection System/Remedial Action Scheme.

3) The definition of UVLS Program is independent of whether the undervoltage load shedding relays are armed manually or automatically since the arming is done in anticipation of extreme conditions and not during the events when load shedding needs to occur.

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Revision History for RSAW

Version	Date	Reviewers	Revision Description
1	2/19/2015	NERC Compliance, Standards	New Document for PRC-010-2 based on RSAW version for PRC-010-1.

[i] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

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Violation Risk Factors and Violation Severity Level Justifications

PRC-004-3 – Protection System Misoperation Identification and Correction

Project 2010-05.1 – Protection System (Misoperations)

Violation Risk Factor and Violation Severity Level Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in: PRC-004-3 – Protection System Misoperation Identification and Correction.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the base penalty amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Protection System Misoperations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project.

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if

violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

The standard drafting team (SDT) also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VRF Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System: [2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination

[1] *N. Am. Elec. Reliability Corp.*, 119 FERC ¶ 61,145 (2007) ("VRF Order"), *order on reh'g and compliance filing*, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] *Id.* at fn 15.

- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

VRF Discussion

The discussion below in the tables addresses how the SDT considered FERC's VRF Guidelines 1 through 5. PRC-004-3 – Protection System Misoperation Identification and Correction is a

revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations and combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

The proposed PRC-004-3 Reliability Standard has six (6) discrete requirements that incorporate and enhance the intent of the requirements of PRC-004-2.1a and PRC-003-1.[3] First, the revised standard requires the Transmission Owner, Generator Owner, and Distribution Provider to review each BES interrupting device operation meeting the criteria in Requirement R1, which includes: when caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate and identify each that is a Misoperation; regardless of whether the BES interrupting device owner owns all or part of the Composite Protection System; and when BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation.

Second, the BES interrupting device owner is required to notify the other Composite Protection System component owner(s) when the criteria in Requirement R2 are met, which includes: Composite Protection System ownership is shared with another owner; the BES interrupting device owner determined that a Misoperation occurred or cannot rule out a Misoperation; and the BES interrupting device owner determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or is unsure.

Third, if a Transmission Owner, Generator Owner, or Distribution Provider is notified by a BES interrupting device owner that the Composite Protection System operated, it must review the operation according to Requirement R3. In most cases, Requirement R1 or R3 will reveal the cause of the Misoperation. If not, Requirement R4 mandates the entity perform investigative action(s) to determine the cause(s) as the fourth discrete Requirement. If a cause is not identified, the entity either may continue its investigation until a cause is identified or the entity may write a declaration that no cause was identified. If a cause is identified, the entity advances to the fifth Requirement.

In Requirement R5, the entity whose Protection System component was identified as the cause of the Misoperation must either develop a Corrective Action Plan (CAP) or explain in a declaration why it cannot correct the cause of the Misoperation. In developing a Corrective Action Plan (CAP) for the identified Protection System component(s), the entity must perform an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. If the entity determines that corrective actions are beyond the entity's control or would not improve BES reliability, it must explain this in a declaration why no further corrective actions will be taken.

In the last Requirement R6, the entity must implement and complete the CAP. The entity must update the CAP during implementation when actions or timetables change.

[3] The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations.

The requirements of the proposed PRC-004-3 do not map, one-to-one, with the Requirements of the two legacy standards, PRC-003-1 and PRC-004-2.1a. The new Requirements comingle various reliability attributes of the legacy standards with precise reliability objectives. In developing the new VRFs for the Requirements of PRC-004-3, the Standard Drafting Team carefully considered the NERC criteria for developing VRFs, as well as the FERC VRF guidelines. The VRFs of the FERC approved PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations (R1 & R2 – High VRF), PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation (R1 – Lower VRF), PRC-016-0.1 – Special Protection System Misoperation (R2 – Medium VRF), and PRC-022-1 – Under-Voltage Load Shedding Program Performance (R1 & R1.5 – Medium VRF), all influenced (citing FERC VRF Guideline 3) the drafting team's VRF decisions, as such, the VRFs for PRC-004-3 Requirements R1 through R6 are assigned a VRF of Medium.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

Violation severity levels should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order on Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

Guideline 2a: A violation of a "binary" type requirement must be a "Severe" VSL.

Guideline 2b: Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF and VSL Justifications – PRC-004-3, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to review each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate for Misoperation could, in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Composite Protection System operations reviewed for proper operation by an owner is the first step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is not in itself likely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that zone 3 relays increased the severity of the blackout. Reviewing Protection Systems for Misoperation, identifying an unnecessary operation and taking corrective actions would reduce the likelihood of reoccurrence. This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards:

VRF and VSL Justifications – PRC-004-3, R1	
	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO), which both have a VRF of "High." The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan". The performance activity that has been isolated in Requirement R1 of PRC-004-3, to "review" (similar to "analyze"), is consistent with similar requirements in Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 ("…shall analyze its SPS operations and maintain a record of all misoperations…") and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 ("…shall analyze and document all UVLS operations and Misoperations.") which both have a VRF of Medium. A VRF of Medium does not inadvertently lower the current VRF of High in the former PRC-004-2.1a, Requirements R1 and R2, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement comingles multiple activities
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to review each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate for Misoperation could, in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Protection System operations reviewed for proper operation by their owner(s) is the first step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

VRF and VSL Justifications – PRC-004-3, R1			
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		

VRF and VSL Justifications – PRC-004-3, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan.” The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. This VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The VSLs appropriately assess the severity of the violation with the failure to perform a review for Misoperation as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.

VRF and VSL Justifications – PRC-004-3, R1	
Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-004-3, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to notify the other owner(s) of a Composite Protection System when the initiating owner determined its Protection System components did not cause a Misoperation or it did not rule out a Misoperation, could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.

VRF and VSL Justifications – PRC-004-3, R2	
	Unresolved Misoperations of Composite Protection Systems owned by others that are not ruled out as a Misoperation could affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system by creating a gap in analysis.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: This is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages. A lack of coordination on system protection was one of eight factors common to substantive outages prior to and including the August 14, 2003 Blackout. The initiating entity in the planning time frame is required to notify the other owner(s) of the Composite Protection System component(s) when it determines that (or is unsure whether)its component(s) did not cause a Misoperation or when it is unable to rule out a Misoperation of the Composite Protection System owned by others. This ensures that all owners review their equipment for proper operation which may include checking for proper coordination depending on the circumstances.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards:

VRF and VSL Justifications – PRC-004-3, R2	
	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO), which both have a VRF of High. The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan". This requirement and a VRF assignment of Medium is consistent, for example, with Reliability Standards FAC-008-3 – Facility Ratings, R7 ("…shall provide Facility Ratings (for its solely and jointly owned Facilities…"), MOD-012-0 – Dynamics Data for Modeling and Simulation of the Interconnected Transmission System, R2 ("…shall provide appropriate equipment characteristics and system data…"), IRO-015-1 – Special Protection System Data and Documentation, R1.1 ("…shall make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas."), and IRO-016-1 – Coordination of Real-time Activities Between Reliability Coordinators, R1 ("…shall contact the other Reliability Coordinator(s) to confirm that there is a problem and then discuss options and decide upon a solution to prevent or resolve the identified problem.") which all have a VRF of Medium. Other Protection Systems based Reliability Standards such as PRC-005-1b – Transmission and Generation Protection System Maintenance and Testing, R2 ("…shall provide documentation…"), PRC-016-0.1 – Special Protection System Misoperations, R3 ("…that owns an SPS shall provide documentation of the misoperation analyses…"), and PRC-017-0 – Special Protection System Maintenance and Testing, R2 ("…SPS shall provide documentation of the program…) all have a VRF of Lower; however, these requirements involve the administrative reporting to either the Regional Reliability Organization (now Regional Entity) or NERC and not a reliability function like the previously mentioned FAC-008-3 and MOD-012-0 Reliability Standards. As such, this Requirement R2 is assigned a VRF of Medium because it has a reliability need to be communicated to other owners.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs:

VRF and VSL Justifications – PRC-004-3, R2			
	Failure to notify other entities to review each Protection System operation, identify Misoperations, and determine the cause could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Unresolved Misoperations of Composite Protection Systems owned by others that are not ruled out as a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR

VRF and VSL Justifications – PRC-004-3, R2			
			The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is new to the standard and had no previous level of compliance. Other Reliability Standards use a variety of VSLs ranging from a single severe level (i.e., binary), two levels, to four VSL levels. Some use a percentage as the failure of the number entities not notified; however, this would not be practical for this requirement as Composite Protection Systems that are owned by multiple entities is generally limited to one or two owners. The incremental increase in violation is consistent with the NERC Guidelines and is reasonable in consideration of the time periods provided by the Requirement.		
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b:		

VRF and VSL Justifications – PRC-004-3, R2	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-004-3, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure of another Composite Protection System owner to review its component(s) for Misoperation, upon notification, for each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Composite Protection System operations reviewed for proper operation by the other owner(s) is an important step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that zone 3 relays increased the severity of the blackout. Reviewing Protection Systems for Misoperation, identifying an unnecessary operation and taking corrective actions would reduce the likelihood of reoccurrence. This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.

VRF and VSL Justifications – PRC-004-3, R3	
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which both have a VRF of High. This Requirement R3, to "review" (similar to "analyze"), comports with Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 ("…shall analyze its SPS operations and maintain a record of all misoperations…") and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 ("…shall analyze and document all UVLS operations and Misoperations.") which both have a VRF of Medium. A VRF of Medium does not inadvertently lower the current VRF of High in the former PRC-004-2.1a, Requirements R1 and R2, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure of another Composite Protection System owner to review its component(s) for Misoperation, upon notification, for each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Composite Protection System operations reviewed for proper operation by the other owner(s) is an important step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage.

VRF and VSL Justifications – PRC-004-3, R3			
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		

VRF and VSL Justifications – PRC-004-3, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (DP) and R2 (GO & TO) for the notified Protection System owner. The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. A VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. This VSLs appropriately assess the severity of the violation with the failure to perform investigative actions as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-004-3, R3	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-004-3, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to identify the cause(s) of a Misoperation (if not determined in Requirements R1 or R3) could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.

VRF and VSL Justifications – PRC-004-3, R4	
	An Unidentified cause(s) of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages. The applicable entity must conduct investigative action(s) to determine the cause(s) of a Misoperation, if not determined during the course of a review as proposed in Requirements R1 and R3.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO), which have a VRF of High. The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." This Requirement R4, to perform at least one "investigative action" (similar to "analyze"), comports with Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 ("…shall analyze its SPS operations and maintain a record of all misoperations…") and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 ("…shall analyze and document all UVLS operations and Misoperations.") which both have a VRF of Medium.

VRF and VSL Justifications – PRC-004-3, R4	
	A VRF of Medium is not inadvertently lowering the current VRF of High in the former PRC-004-2.1a, Requirements R1 or R3, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous. This VRF of Medium comports with the VRF assignment of Medium for PRC-004-3, Requirements R1 and R3, which will generally reveal the cause(s) of an identified Misoperation.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to identify the cause(s) of a Misoperation could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Unidentified causes of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

VRF and VSL Justifications – PRC-004-3, R4			
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard.		

VRF and VSL Justifications – PRC-004-3, R4	
	This VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. This VSLs appropriately assess the severity of the violation with the failure to perform investigative actions as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.

VRF and VSL Justifications – PRC-004-3, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-004-3, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to develop a CAP for a Misoperation with an identified cause could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. An unresolved cause of a Misoperation or failing to consider other locations with similar Protection System components could affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.

VRF and VSL Justifications – PRC-004-3, R5	
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis resulted in entities performing corrective actions; however, there were no negative reliability outcomes concerning the development of a Corrective Action Plan (CAP) associated with Protection Systems.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which have a VRF of High. This requirement is consistent with Reliability Standards PRC-016-0.1, R2 ("…shall take corrective actions to avoid future Misoperations"), PRC-022-1, R1.5 ("For any Misoperation, a Corrective Action Plan…"), FAC-003, R5 ("…Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management") all three of which have a VRF of Medium.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to develop a CAP for a Misoperation with an identified cause or failing to consider other locations with similar components could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.

VRF and VSL Justifications – PRC-004-3, R5			
	An unresolved cause of a Misoperation could affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system if the same condition resulted in a future Misoperation.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR

VRF and VSL Justifications – PRC-004-3, R5			
The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. Varying VSLs are provided for the omission of the evaluation when developing the Corrective Action Plan and for failure to develop the evaluation.		
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which have varying VSLs. This VSL does not lower the current level of compliance because the former VSL in PRC-004-2.1a was comingled with the other activities. This Requirement has a Severe VSL for failure to develop the CAP with the other VSLs being based on tardiness of the development.		

VRF and VSL Justifications – PRC-004-3, R5	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.
FERC VSL G4	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-004-3, R5	
Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

VRF and VSL Justification – PRC-004-3, R6	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to implement a CAP for a Misoperation with an identified cause could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. An uncorrected cause of a Misoperation as a result of not implementing a Corrective Action Plan, could affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system since the condition could occur again.

VRF and VSL Justification – PRC-004-3, R6	
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis resulted in entities performing corrective actions; however, there were no negative reliability outcomes concerning the implementation of a Corrective Action Plan (CAP) associated with Protection Systems.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2.1a, R1 (TO & DP) and R2 (GO),which both have a VRF of High. The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan”. This requirement is consistent with Reliability Standards PRC-016-0.1, R2 (“…shall take corrective actions to avoid future misoperations.”) and PRC-022-1, R1.5 (“For any Misoperation, a Corrective Action Plan…”) which both have a VRF of Medium. The proposed VRF of Medium does not inadvertently lower the current VRF of High in the former PRC-004-2.1a, Requirements R1 and R2, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous.

VRF and VSL Justification – PRC-004-3, R6	
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement a Corrective Action Plan for a Misoperation with an identified cause could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. An uncorrected cause of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

VRF and VSL Justification – PRC-004-3, R6	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—The VSLs cover aspects of this Requirement that are not equal in importance and performance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. The proposed VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The proposed Requirement is a Severe VSL for failure to implement the CAP with the Lower VSL being based on the failure of updating the CAP when actions or timetables change which is administrative in nature.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justification – PRC-004-3, R6	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

PRC-004-5 – Protection System Misoperation Identification and Correction

Project 2008-02.2 – Phase 2 UVLS: Misoperations

Requested Approvals

- PRC-004-5 – Protection System Misoperation Identification and Correction

Requested Retirements

- PRC-004-4 – Protection System Misoperation Identification and Correction[1]

Prerequisite Approvals

- PRC-010-2 – Undervoltage Load Shedding

General Considerations

The implementation period is intended to align with the Effective Date of PRC-010-1 or occurring soon thereafter in order to incorporate certain aspects of PRC-022-1 – Under-Voltage Load Shedding Program Performance into PRC-004. PRC-022-1 was retired by PRC-010-1. The Implementation Plan for PRC-010-1[2] allows twelve (12) calendar months after applicable approvals. Version five of PRC-004 is including undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

Applicable Entities

- Transmission Owner
- Generator Owner
- Distribution Provider

[1] PRC-004-4 was adopted by the NERC Board of Trustees on November 13, 2014. PRC-004-4 is pending adoption or approval by applicable governmental authorities. PRC-004-5 will retire PRC-004-3 if PRC-004-4 is not adopted or approved by an applicable governmental authority.

[2] Refer to Project 2008-02.2 on the NERC website. (http://www.nerc.com/pa/Stand/Pages/Project-2008-02_2-Phase-2-Undervoltage-Load-Shedding-UVLS-Misoperations.aspx)

Effective Dates

PRC-004-5 shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. NERC Board of Trustees ("Board") adopted PRC-004-4 and PRC-010-1 and retired PRC-022-1 on November 12, 2014.
2. NERC Standards Committee authorized initial posting of the standard on February 18, 2015.

Description of Current Draft

The UVLSSDT is posting Draft 1 of PRC-004-5 – Protection System Misoperation Identification and Correction for a 45-day initial formal comment period and concurrent/parallel initial ballot in the last ten days of the comment period. The draft contains revisions to the Applicability section to address UVLS equipment.

Anticipated Actions	Date
45-day formal comment period with ballot	February 2015
10-day final ballot	April 2015
Board adoption	May 2015

Project Development Background

The undervoltage load shedding (UVLS) standard drafting team (SDT) was tasked with addressing Misoperation of UVLS equipment during the development of version one of PRC-010 and version three of PRC-004 in Project 2010-05.1 (i.e., Misoperation). This project has been named phase 2 of Project 2008-02 (i.e., UVLS) for clarity purposes. Each SDT for these two projects outlined work necessary to address Misoperation of UVLS equipment. This work was deferred, at the time, because both PRC-010-1 and PRC-004-3 contained dependencies with other projects requiring their completion. This phase two is a continuation of the work performed under the Standards Authorization Request (SAR) for Project 2008-02.

The revisions proposed in Reliability Standard PRC-010-2 meet the following objectives:

- Address the UVLS Misoperation the remaining work due to the retirement of PRC-022-1 (*Undervoltage Load Shedding Program Performance*) during the development of PRC-010-1 (*Undervoltage Load Shedding*)
- Ensure UVLS equipment (i.e., operation or non-operation) within the UVLS Program is assessed and mitigated

Basis for Revision

Originally, Misoperation of UVLS equipment was planned to be appended to a future version of PRC-004 (*Protection System Misoperation Identification and Correction*). The SDT is proposing a two-prong approach by revising both PRC-004 and PRC-010 to address the concern of identifying Misoperations of UVLS equipment in PRC-022-1.

First, the SDT proposes an addition to the Applicability section of PRC-004 to include UVLS that is intended to trip one or more Bulk Electric System (BES) Elements. This is consistent with previous communication to industry about addressing Misoperation of UVLS equipment.[1] Entities will be required to address UVLS that trips a BES Element similarly to other Protection Systems in PRC-004. While the revision to PRC-004 consistent with the communicated approach, the SDT determined that the proposed revision fails to address the performance (operation or non-operations) of UVLS Program equipment not covered by the strict processes of PRC-004.

Second, the SDT is proposing clarifying revisions in PRC-010-2, Requirements R4 and R5 to address UVLS Program equipment performance. These revisions are not requiring UVLS entities to address UVLS protective relays not covered by the strict processes of PRC-004; however, PRC-010-2 is requiring UVLS entities to address the deficiencies (e.g., Misoperations) identified in the assessment performed by Planning Coordinator or Transmission Planner in Requirement R4. Deficiencies include the performance (operation or non-operation) issues of UVLS Program equipment. These deficiencies, if any, are addressed by the UVLS entities through a Corrective Action Plan (CAP) developed in Requirement R5 and executed by the UVLS entities in Requirement R2 of PRC-010.

The term “Misoperation” as defined by the *Glossary of Terms Used in NERC Reliability Standards* is not used within the Requirements of PRC-010; however, the term is used in the Guidelines and Technical Basis section of the standard to provide clarity that UVLS Program equipment deficiencies include Misoperations that are to be corrected by UVLS entities. The PRC-010-2 Reliability Standard mandates that UVLS entities are to correct the deficiencies identified by the Planning Coordinator or Transmission Planner, such as Misoperation of UVLS equipment. Deficiencies are identified through either the periodic assessment or an assessment performed following an event and included in a CAP to the UVLS entity. The structure used by the SDT allows the Planning Coordinator and Transmission Planner to assess UVLS equipment for Misoperation under PRC-010 rather than the Generator Owner, Transmission Owner, and Distribution Provider applicable to the strict processes of PRC-004.

The two-pronged approach ensures that any UVLS Program equipment containing a deficiency is identified and corrected under PRC-010 and UVLS that trips a BES Element under is corrected under PRC-004 to address the requirements in the retired PRC-022-1.

[1] Refer to Implementation Plan for PRC-010-1 (http://www.nerc.com/pa/stand/Pages/PRC0101RI.aspx) and PRC-010-1 (http://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx), Introduction in the Guidelines and Technical Basis, last paragraph.

A. Introduction

1. **Title: Protection System Misoperation Identification and Correction**

2. **Number:** PRC-004-5

3. **Purpose:** Identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Generator Owner

   4.1.3 Distribution Provider

   4.2. Facilities:

   4.2.1 Protection Systems for BES Elements, with the following exclusions:

   4.2.1.1 Non-protective functions that are embedded within a Protection System.

   4.2.1.2 Protective functions intended to operate as a control function during switching.[2]

   4.2.1.3 Special Protection Systems (SPS).

   4.2.1.4 Remedial Action Schemes (RAS).

   4.2.1.5 Protection Systems of individual dispersed power producing resources identified under Inclusion I4 of the BES definition where the Misoperations affected an aggregate nameplate rating of less than or equal to 75 MVA of BES Facilities.

   4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

   4.2.3 Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

5. **Effective Date:** See Project 2008-02.2 Implementation Plan.

[2] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in Parts 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation: *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and

1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and

1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or was caused by manual intervention in response to its Protection System failure to operate.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified the Misoperation of its Protection System component(s), if any, that meet the circumstances in Requirement R1, Parts 1.1, 1.2, and 1.3 within the allotted time period. Acceptable evidence for Requirement R1, including Parts 1.1, 1.2, and 1.3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in Parts 2.1 and 2.2. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

2.1 For a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a Protection System failure to operate, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances:

2.1.1 The BES interrupting device owner shares the Composite Protection System ownership with any other owner; and

2.1.2 The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and

2.1.3 The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.

2.2 For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's BES Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates notification to the other owner(s), within the allotted time period for either Requirement R2, Part 2.1, including subparts 2.1.1, 2.1.2, and 2.1.3 and Requirement R2, Part 2.2. Acceptable evidence for Requirement R2, including Parts 2.1 and 2.2 may include, but is not limited to the following dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified whether its Protection System component(s) caused a Misoperation within the allotted time period. Acceptable evidence for Requirement R3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment, Operations Planning]*

- The identification of the cause(s) of the Misoperation; or
- A declaration that no cause was identified.

M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it performed at least one investigative action according to Requirement R4 every two full calendar quarters until a cause is identified or a declaration is made. Acceptable evidence for Requirement R4 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations; or
- Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it developed a CAP and an evaluation of the CAP's applicability to other Protection Systems and locations, or a declaration in accordance with Requirement R5. Acceptable evidence for Requirement R5 may include, but is not limited to the following dated documentation (electronic or hardcopy format): CAP and evaluation, or declaration.

R6. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. *[Violation Risk Factor: Medium][Time Horizon: Operations Planning, Long-Term Planning]*

M6. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables. Acceptable evidence for Requirement R6 may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirements R1, R2, R3, and R4, Measures M1, M2, M3, and M4 for a minimum of 12 calendar months following the completion of each Requirement.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R5, Measure M5, including any supporting analysis per Requirements R1, R2, R3, and R4, for a minimum of 12 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R6, Measure M6 for a minimum of 12 calendar months following completion of each CAP.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None**.**

D. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Assessment, Operations Planning	Medium	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Assessment, Operations Planning	Medium	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning, Long-Term Planning	Medium	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR (See next page)

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	(Continued)		The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
R6	Operations Planning, Long-Term Planning	Medium	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

E. Regional Variances

None.

F. Interpretations

None.

G. Associated Documents

NERC System Protection and Controls Subcommittee of the NERC Planning Committee, Assessment of Standards: PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, PRC-004-1 – Analysis and Mitigation of Transmission and Generation Protection Misoperations, PRC-016-1 – Special Protection System Misoperations, May 22, 2009.[3]

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 2. Added "periods" to items where appropriate. 3. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06
1a	February 17, 2011	Adopted by NERC Board of Trustees	Project 2009-17 interpretation adding Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers

[3] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-003-004-016%20Report.pdf

Version	Date	Action	Change Tracking
1a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 1	FERC's Order approving the interpretation of R1 and R3 is effective as of September 26, 2011
2	August 5, 2010	Adopted by NERC Board of Trustees	Project 2010-12 modifications to address Order No. 693 Directives contained in paragraph 1469
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	FERC's Order approving the interpretation of R1 and R3 is effective as of September 26, 2011
2.1a	February 9, 2012	Adopted by NERC Board of Trustees	Errata change under Project 2010-07 to add "…and generator interconnection Facility…"
3	August 14, 2014	Adopted by NERC Board of Trustees	Revision under Project 2010-05.1
4	November 13, 2014	Adopted by NERC Board of Trustees	Applicability revision under Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources
5		Adopted by NERC Board of Trustees	Revision under Project 2008-02.2

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[4] from Gerry Cauley, NERC President and CEO, dated January 7, 2011.

> "Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure. …Relays can misoperate, either operate when not needed or fail to operate when needed, for a number of reasons. First, the device could experience an internal failure – but this is rare. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies. Preventable errors can be introduced by field personnel and their supervisors or more programmatically by the organization."

The standard also addresses the findings in the *2011 Risk Assessment of Reliability Performance*[5]; July 2011.

> "…a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry."

The *State of Reliability 2014*[6] report continued to identify Protection System Misoperations as a significant contributor to automatic transmission outage severity. The report recommended completion of the development of PRC-004-3 as part of the solution to address Protection System Misoperations.

Definitions

The Misoperation definition is based on the IEEE/PSRC Working Group I3 "Transmission Protective Relay System Performance Measuring Methodology[7]." Misoperations of a Protection System include failure to operate, slowness in operating, or operating when not required either during a Fault or non-Fault condition.

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[4] http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf

[5] "2011 Risk Assessment of Reliability Performance." NERC. http://www.nerc.com/files/2011_RARPR_FINAL.pdf. July 2011. Pg. 3.

[6] "State of Reliability 2014." NERC. http://www.nerc.com/pa/Stand/Pages/RelaibilityCoordinationProject20066.aspx. May 2014. Pg. 18 of 106.

[7] "Transmission Protective Relay System Performance Measuring Methodology." Working Group I3 of Power System Relaying Committee of IEEE Power Engineering Society. 1999.

For reference, a "Protection System" is defined in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary") as:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

A BES interrupting device is a BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current. Although BES interrupting device mechanisms are not part of a Protection System, the standard uses the operation of a BES interrupting device by a Protection System to initiate the review for Misoperation.

The following two definitions are being proposed for inclusion in the NERC Glossary:

> **Composite Protection System –** *The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded.*

The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation.

Composite Protection System – Line Example

The Composite Protection System of the Alpha-Beta line (Circuit #123) is comprised of current differential, permissive overreaching transfer trip (POTT), step distance (classic zone 1, zone 2, and zone 3), instantaneous-overcurrent, time-overcurrent, out-of-step, and overvoltage protection. The protection is housed at the Alpha and Beta substations, and includes the associated relays, communications systems, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Transformer Example

The Composite Protection System of the Alpha transformer (#2) is comprised of internal differential, overall differential, instantaneous-overcurrent, and time-overcurrent protection. The protection is housed at the Alpha substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Generator Example

The Composite Protection System of the Beta generator (#3) is comprised of generator differential, overall differential, overcurrent, stator ground, reverse power, volts per hertz, loss-of-field, and undervoltage protection. The protection is housed at the Beta generating plant and at the Beta substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Breaker Failure Example

Breaker failure protection provides backup protection for the breaker, and therefore is part of the breaker's Composite Protection System. Considering breaker failure protection to be part of another Element's Composite Protection System could lead to an incorrect conclusion that a breaker failure operation automatically satisfies the "Slow Trip" criteria of the Misoperation definition.

- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. The breaker failure relaying operated because of a failed trip coil. The failed trip coil caused a Misoperation of the line's Composite Protection System.
- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. Only the breaker failure relaying operated because of a failed breaker mechanism. This was not a Misoperation because the breaker mechanism is not part of the breaker's Composite Protection System.
- An example of an "Unnecessary Trip – During Fault" is when the breaker failure relaying tripped at the same time as the line relaying during a Fault. The Misoperation was due to the breaker failure timer being set to zero.

Misoperation – *The failure a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:*

1. **Failure to Trip – During Fault** *– A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
2. ***Failure to Trip – Other Than Fault*** *– A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*

3. ***Slow Trip – During Fault*** *– A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
4. ***Slow Trip – Other Than Fault*** *– A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
5. ***Unnecessary Trip – During Fault*** *– An unnecessary Composite Protection System operation for a Fault condition on another Element.*
6. ***Unnecessary Trip – Other Than Fault*** *– An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.*

The Misoperation definition is based on the principle that an Element's total complement of protection is intended to operate dependably and securely.

- Failure to automatically reclose after a Fault condition is not included as a Misoperation because reclosing equipment is not included within the definition of Protection System.
- A breaker failure operation does not, in itself, constitute a Misoperation.
- A remote backup operation resulting from a "Failure to Trip" or a "Slow Trip" does not, in itself, constitute a Misoperation.

This proposed definition of Misoperation provides additional clarity over the current version. A Misoperation is the failure of a Composite Protection System to operate as intended for protection purposes. The definition includes six categories which provide further differentiation of what constitutes a Misoperation. These categories are discussed in greater detail in the following sections.

Failure to Trip – During Fault

This category of Misoperation typically results in the Fault condition being cleared by remote backup Protection System operation.

> **Example 1a:** A failure of a transformer's Composite Protection System to operate for a transformer Fault is a Misoperation.
>
> **Example 1b:** A failure of a "primary" transformer relay (or any other component) to operate for a transformer Fault is not a "Failure to Trip – During Fault" Misoperation as long as another component of the transformer's Composite Protection System operated.
>
> **Example 1c:** A lack of target information does not by itself constitute a Misoperation. When a high-speed pilot system does not target because a high-speed zone element trips first, it would not in and of itself be a Misoperation.
>
> **Example 1d:** A failure of an overall differential relay to operate is not a "Failure to Trip – During Fault" Misoperation as long as another component such as a generator differential relay operated.

Example 1e: The Composite Protection System for a bus does not operate during a bus Fault which results in the operation of all local transformer Protection Systems connected to that bus and all remote line Protection Systems connected to that bus isolating the faulted bus from the grid. The operation of the local transformer Protection Systems and the operation of all remote line Protection Systems correctly provided backup protection. There is one "Failure to Trip – During Fault" Misoperation of the bus Composite Protection System.

In analyzing the Protection System for Misoperation, the entity must also consider whether the "Slow Trip – During Fault" category applies to the operation.

Failure to Trip – Other Than Fault

This category of Misoperation may have resulted in operator intervention. The "Failure to Trip – Other Than Fault" conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Example 2a: A failure of a generator's Composite Protection System to operate for an unintentional loss of field condition is a Misoperation.

Example 2b: A failure of an overexcitation relay (or any other component) is not a "Failure to Trip – Other Than Fault" Misoperation as long as the generator's Composite Protection System operated as intended isolating the generator from the BES.

In analyzing the Protection System for Misoperation, the entity must also consider whether the "Slow Trip – Other Than Fault" category applies to the operation.

Slow Trip – During Fault

This category of Misoperation typically results in remote backup Protection System operation before the Fault is cleared.

Example 3a: A Composite Protection System that is slower than required for a Fault condition is a Misoperation if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. The current differential element of a multiple function relay failed to operate for a line Fault. The same relay's time-overcurrent element operated after a time delay. However, an adjacent line also operated from a time-overcurrent element. The faulted line's time-overcurrent element was found to be set to trip too slowly.

Example 3b: A failure of a breaker's Composite Protection System to operate as quickly as intended to meet the expected critical Fault clearing time for a line Fault in conjunction with a breaker failure (i.e., stuck breaker) is a Misoperation if it resulted in an unintended operation of at least one other Element's Composite Protection System. If a generating unit's Composite Protection System operates due to instability caused by the slow trip of the breaker's Composite Protection System, it is not an "Unnecessary Trip – During Fault" Misoperation of the generating unit's Composite Protection System. This event would be a "Slow Trip – During Fault" Misoperation of the breaker's Composite Protection System.

> **Example 3c:** A line connected to a generation interconnection station is protected with two independent high-speed pilot systems. The Composite Protection System for this line also includes step distance and time-overcurrent schemes in addition to the two pilot systems. During a Fault on this line, the two pilot systems fail to operate and the time-overcurrent scheme operates clearing the Fault with no generating units or other Elements tripping (i.e., no over-trips). This event is not a Misoperation.

The phrase “slower than required” means the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

The phrase “resulted in the operation of any other Composite Protection System” refers to the need to ensure that relaying operates in the proper or planned sequence (i.e., the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).

In analyzing the Protection System for Misoperation, the entity must also consider the “Unnecessary Trip – During Fault” category to determine if an “unnecessary trip” applies to the Protection System operation of an Element other than the faulted Element.

If a coordination error was at the local terminal (i.e., set too slow), then it was a "Slow Trip," category of Misoperation at the local terminal.

Slow Trip – Other Than Fault

The phrase “slower than required” means the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

> **Example 4:** A phase to phase fault occurred on the terminals of a generator. The generator's Composite Protection System and a transmission line's Composite Protection System both operated in response to the fault. It was found during subsequent investigation that the generator protection contained an inappropriate time delay. This caused the transmission line's correctly set overreaching zone of protection to operate. This was a Misoperation of the generator’s Composite Protection System, but not of the transmission line’s Composite Protection System.

The “Slow Trip – Other Than Fault” conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Unnecessary Trip – During Fault

An operation of a properly coordinated remote Protection System is not in and of itself a Misoperation if the Fault has persisted for a sufficient time to allow the correct operation of the Composite Protection System of the faulted Element to clear the Fault. A BES interrupting device failure, a “failure to trip” Misoperation, or a “slow trip” Misoperation may result in a proper remote Protection System operation.

> **Example 5:** An operation of a transformer's Composite Protection System which trips (i.e., over-trips) for a properly cleared line Fault is a Misoperation. The Fault is cleared properly by the faulted equipment's Composite Protection System (i.e., line relaying) without the need for an external Protection System operation resulting in an unnecessary trip of the transformer protection; therefore, the transformer Protection System operation is a Misoperation.
>
> **Example 5b:** An operation of a line's Composite Protection System which trips (i.e., over-trips) for a properly cleared Fault on a different line is a Misoperation. The Fault is cleared properly by the faulted line's Composite Protection System (i.e., line relaying); however, elsewhere in the system, a carrier blocking signal is not transmitted (e.g., carrier ON/OFF switch found in OFF position) resulting in the operation of a remote Protection System, single-end trip of a non-faulted line. The operation of the Protection System for the non-faulted line is an unnecessary trip during a Fault. Therefore, the non-faulted line Protection System operation is an “Unnecessary Trip – During Fault” Misoperation.
>
> **Example 5c:** If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip – During Fault" category of Misoperation at the remote terminal.

Unnecessary Trip – Other Than Fault

Unnecessary trips for non-Fault conditions include but are not limited to: power swings, overexcitation, loss of excitation, frequency excursions, and normal operations.

> **Example 6a:** An operation of a line's Composite Protection System due to a relay failure during normal operation is a Misoperation.
>
> **Example 6b:** Tripping a generator by the operation of the loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation assuming the Composite Protection System was not intended to operate under this condition.
>
> **Example 6c:** An impedance line relay trip for a power swing that entered the relay’s characteristic is a Misoperation if the power swing was stable and the relay operated because power swing blocking was enabled and should have prevented the trip, but did not.
>
> **Example 6d:** Tripping a generator operating at normal load by the operation of a reverse power protection relay due to a relay failure is a Misoperation.

Additionally, an operation that occurs during a non-Fault condition but was initiated directly by on-site (i.e., real-time) maintenance, testing, inspection, construction, or commissioning is not a Misoperation.

> **Example 6e:** A BES interrupting device operation that occurs at the remote end of a line during a non-Fault condition because a direct transfer trip was initiated by system maintenance and testing activities at the local end of the line is not a Misoperation because of the maintenance exclusion in category 6 of the definition of "Misoperation."

The "on-site" activities at one location that initiates a trip to another location are included in this exemption. This includes operation of a Protection System when energizing equipment to facilitate measurements, such as verification of current circuits as a part of performing commissioning; however, once the maintenance, testing, inspection, construction, or commissioning activity associated with the Protection System is complete, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of on-site personnel.

Special Cases

Protection System operations for these cases would not be a Misoperation.

> **Example 7a:** A generator Protection System operation prior to closing the unit breaker(s) is not a Misoperation provided no in-service Elements are tripped.

This type of operation is not a Misoperation because the generating unit is not synchronized and is isolated from the BES. Protection System operations that occur when the protected Element is out of service and that do not trip any in-service Elements are not Misoperations.

In some cases where zones of protection overlap, the owner(s) of Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element.

> **Example 7b:** The high-side of a transformer connected to a line may be within the zone of protection of the supplying line's relaying. In this case, the line relaying is planned to protect the area of the high-side of the transformer and into its primary winding. In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for Faults on the high-side of the connected transformer. Therefore, the operation of the line relaying for a high-side transformer Fault operated as intended and would not be a Misoperation.

Below are examples of conditions that would be a Misoperation.

> **Example7c:** A 230 kV shunt capacitor bank was released for operational service. The capacitor bank trips due to a settings error in the capacitor bank differential relay upon energization.

> **Example 7d:** A 230/115 kV BES transformer bank trips out when being re-energized due to an incorrect operation of the transformer differential relay for inrush after being released for operational service. Only the high-side breaker opens since the low-side breaker had not yet been closed.

Non-Protective Functions

BES interrupting device operations which are initiated by non-protective functions, such as those associated with generator controls, excitation controls, or turbine/boiler controls, static voltampere-reactive compensators (SVC), flexible ac transmission systems (FACTS), high-voltage dc (HVdc) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. The standard is not applicable to non-protective functions such as automation (e.g., data collection) or control functions that are embedded within a Protection System.

Control Functions

The entity must make a determination as to whether the standard is applicable to each operation of its Protection System in accordance with the provided exclusions in the standard's Applicability, see Section 4.2.1. The subject matter experts (SME) developing this standard recognize that entities use Protection Systems as part of a routine practice to control BES Elements. This standard is not applicable to operation of protective functions within a Protection System when intended for controlling a BES Element as a part of an entity's process or planned switching sequence. The following are examples of conditions to which this standard is not applicable:

> **Example 8a:** The reverse power protective function that operates to remove a generating unit from service using the entity's normal or routine process.
>
> **Example 8b:** The reverse power relay enables a permissive trip and the generator operator trips the unit.

The standard is not applicable to operation of the protective relay because its operation is intended as a control function as part of a controlled shutdown sequence for the generator. However, the standard remains applicable to operation of the reverse power relay when it operates for conditions not associated with the controlled shutdown sequence, such as a motoring condition caused by a trip of the prime mover.

The following is another example of a condition to which this standard is not applicable:

> **Example 8c:** Operation of a capacitor bank interrupting device for voltage control using functions embedded within a microprocessor based relay that is part of a Protection System.

The above are examples only, and do not constitute an all-inclusive list to which the standard is not applicable.

Extenuating Circumstances

In the event of a natural disaster or other extenuating circumstances, the December 20, 2012 Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, reads: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." The Regional Entities to whom NERC has delegated

authority will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.

The volume of Protection System operations tend to be sporadic. If a high rate of Protection System operations is not sustained, utilities will have an opportunity to catch up within the 120 day period.

Requirement Time Periods

The time periods within all the Requirements are distinct and separate. The applicable entity in Requirement R1 has 120 calendar days to identify whether a BES interrupting device operation is a Misoperation. Once the applicable entity has identified a Misoperation, it has completed its performance under Requirement R1. Identified Misoperations without an identified cause become subject to Requirement R4 and any subsequent Requirements as necessary. Identified Misoperations with an identified cause become subject to Requirement R5 and any subsequent Requirements as necessary.

In Requirement R2, the applicable entity has 120 calendar days, based on the date of the BES interrupting device operation, to provide notification to the other Protection System owners that meet the circumstances in Parts 2.1 and 2.2. For the case of an applicable entity that was notified (R3), it has the later of 120 calendar days from the date of the BES interrupting device operation or 60 calendar days of notification to identify whether its Protection System components caused a Misoperation.

Once a Misoperation is identified in either Requirement R1 or R3, and the applicable entity did not identify the cause(s) of the Misoperation, the time period for performing at least one investigative action every two full calendar quarters begins. The time period(s) in Requirement R4 resets upon each period. When the applicable entity's investigative actions identify the cause of the identified Misoperation or the applicable entity declares that no cause was found, the applicable entity has completed its performance in Requirement R4.

The time period in Requirement R5 begins when the Misoperation cause is first identified. The applicable entity is allotted 60 calendar days to perform one of the two activities listed in Requirement R5 (e.g., CAP or declaration) to complete its performance under Requirement R5.

Requirement R6 time period is determined by the actions and the associated timetable to complete those actions identified in the CAP. The time periods contained in the CAP may change from time to time and the applicable entity is required to update the timetable when it changes.

Time periods provided in the Requirements are intended to provide a reasonable amount of time to perform each Requirement. Performing activities in the least amount of time facilitates prompt identification of Misoperations, notification to other Protection System owners, identification of the cause(s), correction of the cause(s), and that important information is retained that may be lost due to time.

Requirement R1

This Requirement initiates a review of each BES interrupting device operation to identify whether or not a Misoperation may have occurred. Since the BES interrupting device owner typically monitors and tracks device operations, the owner is the logical starting point for identifying Misoperations of Protection Systems for BES Elements. A review is required when (1) a BES interrupting device operates that is caused by a Protection System or by manual intervention in response to a Protection System failure to operate, (2) regardless of whether the owner owns all or part of the Protection System component(s), and (3) the owner identified its Protection System component(s) as causing the BES interrupting device operation or was caused by manual intervention in response to its Protection System failure to operate.

Since most Misoperations result in the operation of one or more BES interrupting devices, these operations initiate a review to identify any Misoperation. If an Element is manually isolated in response to a failure to operate, the manual isolation of the Element triggers a review for Misoperation.

> **Example R1a:** The failure of a loss of field relay on a generating unit where an operator takes action to isolate the unit.

Manual intervention may indicate a Misoperation has occurred, thus requiring the initiation of an investigation by the BES interrupting device owner.

For the case where a BES interrupting device did not operate and remote clearing occurs due to the failure of a Composite Protection System to operate, the BES interrupting device owner would still review the operation under Requirement R1. However, if the BES interrupting device owner determines that its Protection System component operated as backup protection for a condition on another entity's BES Element, the owner would provide notification of the operation to the other Protection System owner(s) under Requirement R2, Part 2.2.

Protection Systems are made of many components. These components may be owned by different entities. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner's differential relay. All of these components and many more are part of a Protection System. It is expected that all of the owners will communicate with each other, sharing information freely, so that Protection System operations can be analyzed, Misoperations identified, and corrective actions taken.

Each entity is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation regardless of the level of ownership. A combination of available information from resources such as counters, relay targets, Supervisory Control and Data Acquisition (SCADA) systems, or DME would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation. The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether its Protection System component(s) caused a Misoperation.

The Protection System operation may be documented in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System.

Repeated operations which occur during the same automatic reclosing sequence do not need a separate identification under Requirement R1. Repeated Misoperations which occur during the same 24-hour period do not need a separate identification under Requirement R1. This is consistent with the NERC *Misoperations Report*[8] which states:

> "In order to avoid skewing the data with these repeated events, the NERC SPCS should clarify, in the next annual update of the misoperation template, that all misoperations due to the same equipment and cause within a 24 hour period be recorded as one misoperation."

The following is an example of a condition that is not a Misoperation.

> **Example R1b:** A high impedance Fault occurs within a transformer. The sudden pressure relaying detects and operates for the Fault, but the differential relaying did not operate due to the low Fault current levels. This is not a Misoperation because the Composite Protection System was not required to operate because the Fault was cleared by the sudden pressure relay.

Requirement R2

Requirement R2 ensures notification of those who have a role in identifying Misoperations, but were not accounted for within Requirement R1. In the case of multi-entity ownership, the entity that owns the BES interrupting device that operated is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation under Requirement R1; however, if the entity that owns a BES interrupting device determines that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation, it must notify the other Protection System owner(s) that share Misoperation identification responsibility when the criteria in Requirement R2 is met.

This Requirement does not preclude the Protection System owners from initially communicating and working together to determine whether a Misoperation occurred and, if so, the cause. The BES interrupting device owner is only required to officially notify the other owners when it: (1) shares the Composite Protection System ownership with other entity(ies), (2) determines that a Misoperation occurred or cannot rule out a Misoperation, and (3) determines its Protection System component(s) did not cause a Misoperation or is unsure. Officially notifying the other owners without performing a preliminary review may unnecessarily burden the other owners with compliance obligations under Requirement R3, redirect valuable resources, and add little benefit to reliability. The BES interrupting device owner should officially notify other owners when appropriate within the established time period.

[8] "Misoperations Report." Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. April 1, 2013. pg. 37 of 40.

The following is an example of a notification to another Protection System owner:

> **Example R2a:** Circuit breakers A and B at the Charlie station tripped from directional comparison blocking (DCB) relaying on 03/03/2014 at 15:43 UTC during an external Fault. As discussed last week, the fault records indicate that a problem with your equipment (failure to transmit) caused the operation.
>
> **Example R2b:** A generator unit tripped out immediately upon synchronizing to the grid due to a Misoperation of its overcurrent protection. The Transmission Owner owns the 230 kV generator breaker that operated. The Transmission Owner, as the owner of the BES interrupting device after determining that its Protection System components did not cause the Misoperation, notified the Generator Owner of the operation. The Generator Owner investigated and determined that its Protection System components caused the Misoperation. In this example, the Generator Owner's Protection System components did cause the Misoperation. As the owner of the Protection System components that caused the Misoperation, the Generator Owner is responsible for creating and implementing the CAP.

A Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the notification criteria in Part 2.1.1 of Requirement R2. For example, if the same personnel within a registered entity perform the Misoperation identification for both the Generator Owner and Transmission Owner functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be covered in Requirement R1.

> **Example R2c:** Line A Composite Protection System (owned by entity 1) failed to operate for an internal Fault. As a result, the zone 3 portion of Line B's Composite Protection System (owned by entity 2) and zone 3 portion of Line C's Composite Protection System (owned by entity 3) operated to clear the Fault. Entity 2 and 3 notified entity 1 of the remote zone 3 operation.

For the case where a BES interrupting device operates to provide backup protection for a non-BES Element, the entity reviewing the operation is not required to notify the other owners of Protection Systems for non-BES Elements. No notification is required because this Reliability Standard is not applicable to Protection Systems for non-BES Elements.

Requirement R3

For Requirement R3 (i.e., notification received), the entity that also owns a portion of the Composite Protection System is expected to use judgment to identify whether the Protection System operation is a Misoperation. A combination of available information from resources such as counters, relay targets, SCADA, DME, and information from the other owner(s) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. The entity may decide to identify the operation as a

Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation.

The entity that is notified by the BES interrupting device owner is allotted the later of 60 calendar days from receipt of notification or 120 calendar days from the BES interrupting device operation date to determine if its portion of the Composite Protection System caused the Protection System operation. It is expected that in most cases of a jointly owned Protection System, the entity making notification would have been in communication with the other owner(s) early in the process. This means that the shorter 60 calendar days only comes into play if the notification occurs in the second half of the 120 calendar days allotted to the BES interrupting device owner in Requirement R1.

The Protection System review may be organized in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System. The BES interrupting device owner's notification received may be documented in a variety of ways such as an email or a facsimile.

Requirement R4

The entity in Requirement R4 (i.e., cause identification), whether it is the entity that owns the BES interrupting device or an entity that was notified, is expected to use due diligence in taking investigative action(s) to determine the cause(s) of an identified Misoperation for its portion of the Composite Protection System. The SMEs developing this standard recognize there will be cases where the cause(s) of a Misoperation will not be revealed during the allotted time periods in Requirements R1 or R3; therefore, Requirement R4 provides the entity a mechanism to continue its investigative work to determine the cause(s) of the Misoperation when the cause is not known.

A combination of available information from resources such as counters, relay targets, SCADA, DME, test results, and studies would typically be used to determine the cause of the Misoperation. At least one investigative action must be performed every two full calendar quarters until the investigation is completed.

The following is an example of investigative actions taken to determine the cause of an identified Misoperation:

> **Example R4a**: A Misoperation was identified on 03/18/2014. A line outage to test the Protection System was scheduled on 03/24/2014 for 12/15/2014 as the first investigative action (i.e., beyond the next two full calendar quarters) due to summer peak conditions. The protection engineer contacted the manufacturer on 04/10/2014 (i.e., within two full calendar quarters) to obtain any known issues. The engineer reviewed manufacturer's documents on 05/27/2014. The outage schedule was confirmed on 08/29/2014 and was taken on 12/15/2014. Testing was completed on 12/16/2014 (i.e., in the second two full quarters) revealing the microprocessor relay as the cause of the Misoperation. A CAP is being developed to replace the relay.

Periodic action minimizes compliance burdens and focuses the entity's effort on determining the cause(s) of the Misoperation while providing measurable evidence. The SMEs recognize that

certain planned investigative actions may require months or years to schedule and complete; therefore, the entity is only required to perform at least one investigative action every two full calendar quarters. If an investigative action is performed in the first quarter of a calendar year, the next investigative action would need to be performed by the end of the third calendar quarter. If an investigative action is performed in the last quarter of a calendar year, the next investigative action would need to be performed by the end of the second calendar quarter of the following calendar year. Investigative actions may include a variety of actions, such as reviewing DME records, performing or reviewing studies, completing relay calibration or testing, requesting manufacturer review, requesting an outage, or confirming a schedule.

The entity's investigation is complete when it identifies the cause of the Misoperation or makes a declaration that no cause was determined. The declaration is intended to be used if the entity determines that investigative actions have been exhausted or have not provided direction for identifying the Misoperation cause. Historically, approximately 12% of Misoperations are unknown or unexplainable.[9]

Although the entity only has to document its specific investigative actions taken to determine the cause(s) of an identified Misoperation, the entity should consider the benefits of formally organizing (e.g., in a report or database) its actions and findings. Well documented investigative actions and findings may be helpful in future investigations of a similar event or circumstances. A thorough report or database may contain a detailed description of the event, information gathered, investigative actions, findings, possible causes, identified causes, and conclusions. Multiple owners of a Composite Protection System might consider working together to produce a common report for their mutual benefit.

The following are examples of a declaration where no cause was determined:

> **Example R4b**: A Misoperation was identified on 04/11/2014. All relays at station A and B functioned properly during testing on 08/26/2014 as the first investigative action. The carrier system functioned properly during testing on 08/27/2014. The carrier coupling equipment functioned properly during testing on 08/28/2014. A settings review completed on 09/03/2014 indicated the relay settings were proper. Since the equipment involved in the operation functioned properly during testing, the settings were reviewed and found to be correct, and the equipment at station A and station B is already monitored. The investigation is being closed because no cause was found.
>
> **Example R4c:** A Misoperation was identified on 03/22/2014. The protection scheme was replaced before the cause was identified. The power line carrier or PLC based protection was replaced with fiber-optic based protection with an in-service date of 04/16/2014. The new system will be monitored for recurrence of the Misoperation.

Requirement R5

Resolving the causes of Protection System Misoperations benefits BES reliability by preventing recurrence. The Corrective Action Plan (CAP) is an established tool for resolving operational problems. The NERC Glossary defines a Corrective Action Plan as, *"A list of actions and an*

[9] NERC System Protection and Control Subcommittee. Misoperations Report. April 1, 2013: http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. Figure 15: NERC Wide Misoperations by Cause Code. pg. 22 of 40.

associated timetable for implementation to remedy a specific problem." Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the Misoperation cause is identified in Requirement R1, R3 or R4, Requirement R5 requires Protection System owner(s) to develop a CAP, or explain why corrective actions are beyond the entity's control or would not improve BES reliability. The entity must develop the CAP or make a declaration why additional actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken within 60 calendar days of first determining a cause.

The SMEs developing this standard recognize there may be multiple causes for a Misoperation. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple CAP(s) to correct multiple causes of a Misoperation. The 60 calendar day period for developing a CAP (or declaration) is established on the basis of industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent Misoperation recurrence, the timetable for executing such actions, and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. The evaluation of these other Protection Systems aims to reduce the risk and likelihood of similar Misoperations in other Protection Systems. The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection Systems at other locations or the reasoning for not taking any action. The CAP and an evaluation of other Protection Systems including other locations must be developed to complete Requirement R5.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined capacitor replacement was not necessary.

For completion of each CAP in Examples R5a through R5d, please see Examples R6a through R6d.

> **Example R5a:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay has not been experiencing problems and is systematically being replaced with microprocessor relays as Protection Systems are modernized. Therefore, it was assessed that a program for wholesale preemptive replacement of capacitors in this type of impedance relay does not need to be established for the system.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5b:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, a program should be established by 12/01/2014 for wholesale preemptive replacement of capacitors in this type of impedance relay.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5c:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, the preemptive replacement of capacitors in this type of impedance relay should be pursued for the identified stations A through I by 04/30/2015.
>
> A plan is being developed to replace the impedance relay capacitors at stations A, B, and C by 09/01/2014. A second plan is being developed to replace the impedance relay capacitors at stations D, E, and F by 11/01/2014. The last plan will replace the impedance relay capacitors at stations G, H, and I by 02/01/2015.

The following is an example of a CAP for a relay Misoperation that was due to a version 2 firmware problem and the evaluation of the cause at similar locations which determined the firmware needs preemptive correction action.

> **Example R5d:** Actions: Provide the manufacturer fault records. Install new firmware pending manufacturer results by 10/01/2014.
>
> Applicability to other Protection Systems: Based on the evaluation of other locations and a risk assessment, the newer firmware version 3 should be installed at all installations that are identified to be version 2. Twelve relays were identified across the system. Proposed completion date is 12/31/2014.

The following are examples of a declaration made where corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken.

> **Example R5e:** The cause of the Misoperation was due to a non-registered entity communications provider problem.
>
> **Example R5f:** The cause of the Misoperation was due to a transmission transformer tapped industrial customer who initiated a direct transfer trip to a registered entity's transmission breaker.

In situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity's control.

The following are examples of declarations made why corrective actions would not improve BES reliability.

> **Example R5g:** The investigation showed that the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations.
>
> **Example R5h:** As a result of an operation that left a portion of the power system in an electrical island condition, circuit XYZ within that island tripped, resulting in loss of load within the island. Subsequent investigation showed an overfrequency condition persisted after the formation of that island and the XYZ line protective relay operated. Since this relay was operating outside of its designed frequency range and would not be subject to this condition when line XYZ is operated normally connected to the BES, no corrective action will be taken because BES reliability would not be improved.
>
> **Example R5i:** During a major ice storm, four of six circuits were lost at Station A. Subsequent to the loss of these circuits, a skywire (i.e., shield wire) broke near station A on line AB (between Station A and B) resulting in a phase-phase Fault. The protection scheme utilized for both protection groups is a permissive overreaching transfer trip (POTT). The Line AB protection at Station B tripped timed for this event (i.e., Slow Trip – During Fault) even though this line had been identified as requiring high speed clearing. A weak infeed condition was created at Station A due to the loss of 4 transmission circuits resulting in the absence of a permissive signal on Line AB from Station A during this Fault. No corrective action will be taken for this Misoperation as even under N-1 conditions, there is normally enough infeed at Station A to send a proper permissive signal to station B. Any changes to the protection scheme to account for this would not improve BES reliability.

A declaration why corrective actions are beyond the entity's control or would not improve BES reliability should include the Misoperation cause and the justification for taking no corrective action. Furthermore, a declaration that no further corrective actions will be taken is expected to be used sparingly.

Requirement R6

To achieve the stated purpose of this standard, which is to identify and correct the causes of Misoperations of Protection Systems for BES Elements, the responsible entity is required to implement a CAP that addresses the specific problem (i.e., cause(s) of the Misoperation) through completion. Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until completed. Accomplishing this objective is intended to reduce the occurrence of future Misoperations of a similar nature, thereby improving reliability and minimizing risk to the BES.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip (See also, Example R5a).

> **Example R6a:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> CAP completed on 06/25/2014.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip that resulted in the correction and the establishment of a program for further replacements (See also, Example R5b).

> **Example R6b:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> A program for wholesale preemptive replacement of capacitors in this type of impedance relay was established on 10/28/2014.
>
> CAP completed on 10/28/2014.

The following is an example of a completed CAP of corrective actions with a timetable that required updating for a failed relay and preemptive actions for similar installations (See also, Example R5c).

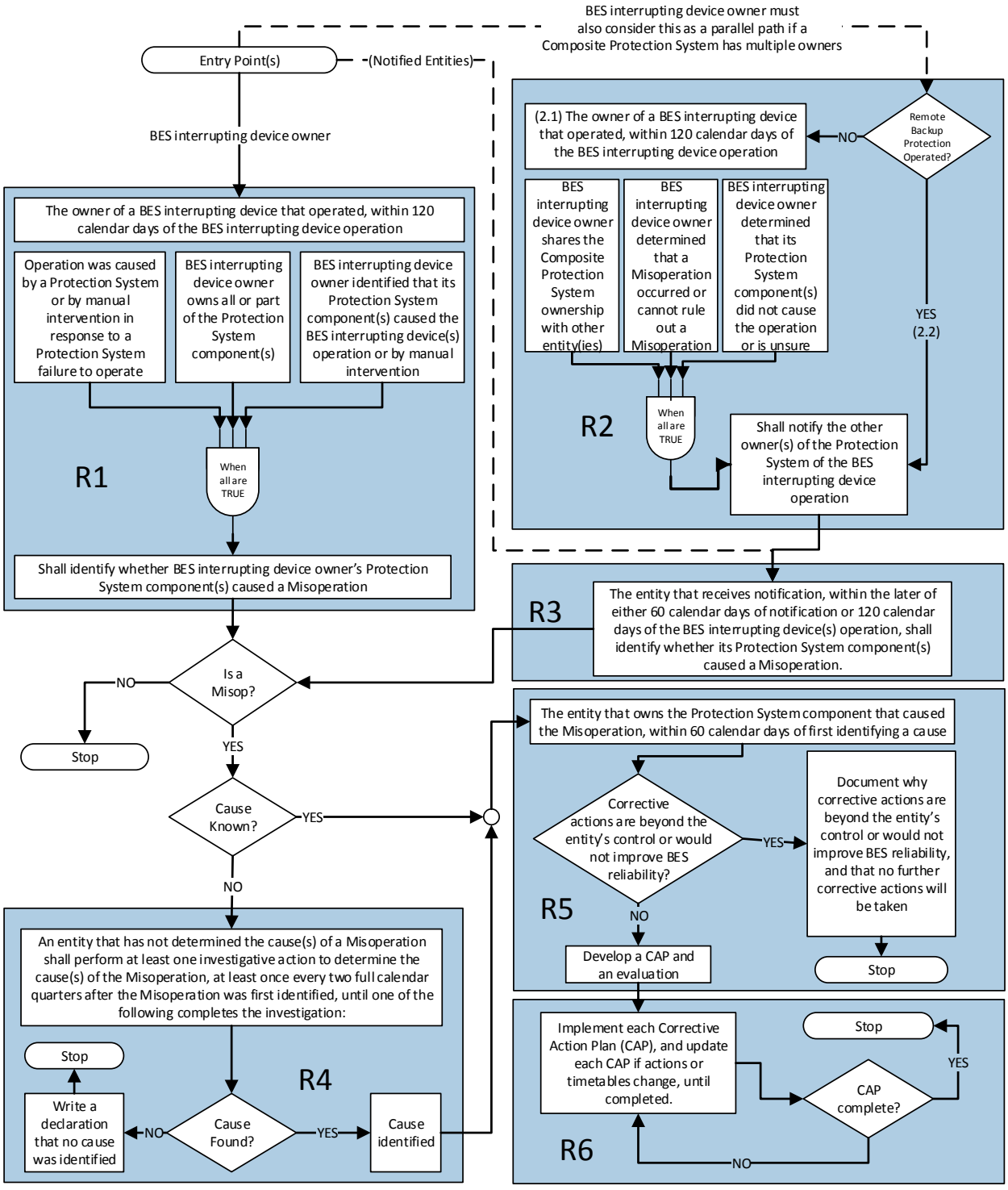
> **Example R6c:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> The impedance relay capacitor replacement was completed at stations A, B, and C on 08/16/2014. The impedance relay capacitor replacement was completed at stations D, E, and F on 10/24/2014. The impedance relay capacitor replacement for stations G, H, and I were postponed due to resource rescheduling from a scheduled 02/01/15 completion to 04/01/2015 completion. Capacitor replacement was completed on 03/09/2015 at stations G, H, and I. All stations identified in the evaluation have been completed.
>
> CAP completed on 03/09/2015.

The following is an example of a completed CAP for corrective actions with updated actions for a firmware problem and preemptive actions for similar installations. (See also, Example R5d).

> **Example R6d:** Actions: fault records were provided to the manufacturer on 06/04/2014. The manufacturer responded that the Misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 08/12/2014.
>
> Nine of the twelve relays were updated to version 3 firmware on 09/23/2014. The manufacturer provided a subsequent update which was determined to be beneficial for the remaining relays. The remaining three of twelve relays identified as having the version 2 firmware were updated to version 3.01 firmware on 11/10/2014.
>
> CAP completed on 11/10/2014.

The CAP is complete when all of the actions identified within the CAP have been completed.

Process Flow Chart: Below is a graphical representation demonstrating the relationships between Requirements:



Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Introduction

The only revisions made to version of PRC-004-4 are revisions to section 4.2 Facilities to clarify applicability of the Requirements of the standard at generator Facilities. These applicability revisions are intended to clarify and provide for consistent application of the Requirements to BES generator Facilities included in the BES through Inclusion I4 – Dispersed Power Producing Resources.

Rationale for Applicability

Misoperations occurring on the Protection Systems of individual generation resources identified under Inclusion I4 of the BES definition do not have a material impact on BES reliability when considered individually; however, the aggregate capability of these resources may impact BES reliability if a number of Protection Systems on the individual power producing resources incorrectly operated or failed to operate as designed during a system event. To recognize the potential for the Protection Systems of individual power producing resources to affect the reliability of the BES, 4.2.1.5 of the Facilities section reflects the threshold consistent with the revised BES definition. See FERC Order Approving Revised Definition, P 20, Docket No. RD14-2-000. The intent of 4.2.1.5 of the Facilities section is to exclude from the standard requirements these Protection Systems for “common- mode failure” type scenarios affecting less than or equal to 75 MVA aggregated nameplate generating capability at these dispersed generating facilities.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. NERC Board of Trustees ("Board") adopted PRC-004-4 and PRC-010-1 and retired PRC-022-1 on November 12, 2014.
2. NERC Standards Committee approved initial posting of the standard on February 18, 2015

Description of Current Draft

The UVLSSDT is posting Draft 1 of PRC-004-5 – Protection System Misoperation Identification and Correction for a 45-day initial formal comment period and concurrent/parallel initial ballot in the last ten days of the comment period. The draft contains revisions to the Applicability section to address UVLS equipment.

Anticipated Actions	Date
45-day formal comment period with ballot	February 2015
10-day final ballot	April 2015
Board adoption	May 2015

Project Development Background

The undervoltage load shedding (UVLS) standard drafting team (SDT) was tasked with addressing Misoperation of UVLS equipment during the development of version one of PRC-010 and version three of PRC-004 in Project 2010-05.1 (i.e., Misoperation). This project has been named phase 2 of Project 2008-02 (i.e., UVLS) for clarity purposes. Each SDT for these two projects outlined work necessary to address Misoperation of UVLS equipment. This work was deferred, at the time, because both PRC-010-1 and PRC-004-3 contained dependencies with other projects requiring their completion. This phase two is a continuation of the work performed under the Standards Authorization Request (SAR) for Project 2008-02.

The revisions proposed in Reliability Standard PRC-010-2 meet the following objectives:

- Address the UVLS Misoperation the remaining work due to the retirement of PRC-022-1 (*Undervoltage Load Shedding Program Performance*) during the development of PRC-010-1 (*Undervoltage Load Shedding*)
- Ensure UVLS equipment (i.e., operation or non-operation) within the UVLS Program is assessed and mitigated

Basis for Revision

Originally, Misoperation of UVLS equipment was planned to be appended to a future version of PRC-004 (*Protection System Misoperation Identification and Correction*). The SDT is proposing a two-prong approach by revising both PRC-004 and PRC-010 to address the concern of identifying Misoperations of UVLS equipment in PRC-022-1.

First, the SDT proposes an addition to the Applicability section of PRC-004 to include UVLS that is intended to trip one or more Bulk Electric System (BES) Elements. This is consistent with previous communication to industry about addressing Misoperation of UVLS equipment.[1] Entities will be required to address UVLS that trips a BES Element similarly to other Protection Systems in PRC-004. While the revision to PRC-004 consistent with the communicated approach, the SDT determined that the proposed revision fails to address the performance (operation or non-operations) of UVLS Program equipment not covered by the strict processes of PRC-004.

Second, the SDT is proposing clarifying revisions in PRC-010-2, Requirements R4 and R5 to address UVLS Program equipment performance. These revisions are not requiring UVLS entities to address UVLS protective relays not covered by the strict processes of PRC-004; however, PRC-010-2 is requiring UVLS entities to address the deficiencies (e.g., Misoperations) identified in the assessment performed by Planning Coordinator or Transmission Planner in Requirement R4. Deficiencies include the performance (operation or non-operation) issues of UVLS Program equipment. These deficiencies, if any, are addressed by the UVLS entities through a Corrective Action Plan (CAP) developed in Requirement R5 and executed by the UVLS entities in Requirement R2 of PRC-010.

The term "Misoperation" as defined by the *Glossary of Terms Used in NERC Reliability Standards* is not used within the Requirements of PRC-010; however, the term is used in the Guidelines and Technical Basis section of the standard to provide clarity that UVLS Program equipment deficiencies include Misoperations that are to be corrected by UVLS entities. The PRC-010-2 Reliability Standard mandates that UVLS entities are to correct the deficiencies identified by the Planning Coordinator or Transmission Planner, such as Misoperation of UVLS equipment. Deficiencies are identified through either the periodic assessment or an assessment performed following an event and included in a CAP to the UVLS entity. The structure used by the SDT allows the Planning Coordinator and Transmission Planner to assess UVLS equipment for Misoperation under PRC-010 rather than the Generator Owner, Transmission Owner, and Distribution Provider applicable to the strict processes of PRC-004.

The two-pronged approach ensures that any UVLS Program equipment containing a deficiency is identified and corrected under PRC-010 and UVLS that trips a BES Element under is corrected under PRC-004 to address the requirements in the retired PRC-022-1.

[1] Refer to Implementation Plan for PRC-010-1 (http://www.nerc.com/pa/stand/Pages/PRC0101RI.aspx) and PRC-010-1 (http://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx), Introduction in the Guidelines and Technical Basis, last paragraph.

A. Introduction

1. **Title: Protection System Misoperation Identification and Correction**

2. **Number:** PRC-004-45

3. **Purpose:** Identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Generator Owner

   4.1.3 Distribution Provider

   4.2. Facilities:

   4.2.1 Protection Systems for BES Elements, with the following exclusions:

   4.2.1.1 Non-protective functions that are embedded within a Protection System.

   4.2.1.2 Protective functions intended to operate as a control function during switching.[2]

   4.2.1.3 Special Protection Systems (SPS).

   4.2.1.4 Remedial Action Schemes (RAS).

   4.2.1.5 Protection Systems of individual dispersed power producing resources identified under Inclusion I4 of the BES definition where the Misoperations affected an aggregate nameplate rating of less than or equal to 75 MVA of BES Facilities.

   4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

   4.2.3 Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

5. **Effective Dates:Date:** See theProject 2008-02.2 Implementation Plan for this Standard..

5. **Background:**

A key factor for BES reliability is the correct performance of Protection Systems. The monitoring of Protection System events for BES Elements, as well as identifying and correcting the causes of Misoperations, will improve Protection System performance. This Reliability Standard PRC-004-3 – Protection System Misoperation Identification and Correction is a revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations. The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation

[2] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations. In the FERC Order No. 693, the Commission identified PRC-003-0 as a "fill-in-the-blank" standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional Entity procedures to support the Requirements of PRC-004-2.1a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

This project includes revising the existing definition of Misoperation, which reads:

Misoperation

- Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection.
- Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

In general, this definition needed more specificity and clarity. The terms "specified time" and "abnormal condition" are ambiguous. In the third bullet, more clarification is needed as to whether an unintentional Protection System operation for an atypical, yet explainable, condition is a Misoperation.

The SAR for this project also included clarifying reporting requirements. Misoperation data, as currently collected and reported, is not optimal to establish consistent metrics for measuring Protection System performance. As such, the data reporting obligation for this standard is being removed and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information ("data request"). As a result of the data request, NERC will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry. The removal of the data collection obligation from the standard does not result in a reduction of reliability. The standard and data request have been developed in a manner such that evidence used for compliance with the standard and data request are intended to be independent of each other.

The proposed Requirements of the revised Reliability Standard PRC-004-3 meet the following objectives:

- Review all Protection System operations on the BES to identify those that are Misoperations of Protection Systems for Facilities that are part of the BES.
- Analyze Misoperations of Protection Systems for Facilities that are part of the BES to identify the cause(s).

- ~~Develop and implement Corrective Action Plans to address the cause(s) of Misoperations of Protection Systems for Facilities that are part of the BES.~~

~~Misoperations associated with Special Protection Schemes (SPS) and Remedial Action Schemes (RAS) are not addressed in this standard due to their inherent complexities. NERC plans to handle SPS and RAS in the second phase of this project.~~

~~The Western Electric Coordinating Council (WECC) Regional Reliability Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation relates to the reporting of Misoperations of Protection Systems and RAS for a limited set of WECC Paths. The WECC region plans to conduct work to harmonize the regional standard with this continent-wide proposed standard and the second phase of this project concerning SPS and RAS.~~

~~Undervoltage load shedding (UVLS) has not been included in this standard's applicability because Misoperations of UVLS relays are currently addressed by Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance, Requirement R1.5. Underfrequency load shedding (UFLS) was added to PRC-004-3 to close a gap in reliability as Misoperations of UFLS relays are not covered by a Reliability Standard currently.~~

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in Parts 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation: *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and

1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and

1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or was caused by manual intervention in response to its Protection System failure to operate.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified the Misoperation of its Protection System component(s), if any, that meet the circumstances in Requirement R1, Parts 1.1, 1.2, and 1.3 within the allotted time period. Acceptable evidence for Requirement R1, including Parts 1.1, 1.2, and 1.3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in Parts 2.1 and 2.2. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

2.1 For a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a Protection System failure to operate, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances:

2.1.1 The BES interrupting device owner shares the Composite Protection System ownership with any other owner; and

2.1.2 The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and

2.1.3 The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.

2.2 For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's BES Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates notification to the other owner(s), within the allotted time period for either Requirement R2, Part 2.1, including subparts 2.1.1, 2.1.2, and 2.1.3 and Requirement R2, Part 2.2. Acceptable evidence for Requirement R2, including Parts 2.1 and 2.2 may include, but is not limited to the following dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified whether its Protection System component(s) caused a Misoperation within the allotted time period. Acceptable evidence for Requirement R3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment, Operations Planning]*

- The identification of the cause(s) of the Misoperation; or
- A declaration that no cause was identified.

M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it performed at least one investigative action according to Requirement R4 every two full calendar quarters until a cause is identified or a declaration is made. Acceptable evidence for Requirement R4 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations; or
- Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it developed a CAP and an evaluation of the CAP's applicability to other Protection Systems and locations, or a declaration in accordance with Requirement R5. Acceptable evidence for Requirement R5 may include, but is not limited to the following dated documentation (electronic or hardcopy format): CAP and evaluation, or declaration.

R6. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. *[Violation Risk Factor: Medium][Time Horizon: Operations Planning, Long-Term Planning]*

M6. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables. Acceptable evidence for Requirement R6 may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirements R1, R2, R3, and R4, Measures M1, M2, M3, and M4 for a minimum of 12 calendar months following the completion of each Requirement.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R5, Measure M5, including any supporting analysis per Requirements R1, R2, R3, and R4, for a minimum of 12 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R6, Measure M6 for a minimum of 12 calendar months following completion of each CAP.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None.

D. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Assessment, Operations Planning	Medium	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Assessment, Operations Planning	Medium	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning, Long-Term Planning	Medium	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR (See next page)

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	(Continued)		The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
R6	Operations Planning, Long-Term Planning	Medium	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

E. Regional Variances

None.

F. Interpretations

None.

G. Associated Documents

NERC System Protection and Controls Subcommittee of the NERC Planning Committee, Assessment of Standards: PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, PRC-004-1 – Analysis and Mitigation of Transmission and Generation Protection Misoperations, PRC-016-1 – Special Protection System Misoperations, May 22, 2009.[3]

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 2. Added "periods" to items where appropriate. 3. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06
~~2~~		~~Modified to address Order No. 693 Directives contained in paragraph 1469.~~	~~Revised~~
~~2~~	~~August 5, 2010~~	~~Adopted by NERC Board of Trustees~~	

[3] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-003-004-016%20Report.pdf

Version	Date	Action	Change Tracking
1a	February 17, 2011	Adopted by NERC Board of Trustees~~Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers~~	Project 2009-17 interpretation adding Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers
~~1a~~	~~February 17, 2011~~	~~Adopted by NERC Board of Trustees~~	
1a	September 26, 2011	Appended FERC ~~Order issued approving the~~ approved interpretation of R1 and R3 ~~(FERC's Order is effective as of September 26, 2011)~~to version 1	FERC's Order approving the interpretation of R1 and R3 is effective as of September 26, 2011
2	August 5, 2010	Adopted by NERC Board of Trustees	Project 2010-12 modifications to address Order No. 693 Directives contained in paragraph 1469
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	FERC's Order approving the interpretation of R1 and R3 is effective as of September 26, 2011
2.1a	February 9, 2012	~~Errata change: Edited R2 to add "…and generator interconnection Facility…"~~Adopted by NERC Board of Trustees	~~Revision~~Errata change under Project 2010-07 to add "…and generator interconnection Facility…"

Version	Date	Action	Change Tracking
~~2.1a~~	~~February 9, 2012~~	~~Errata change adopted by NERC Board of Trustees~~	
~~2.1a~~	~~September 19, 2013~~	~~FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).~~	
3	August 14, 2014	Adopted by NERC Board of Trustees	Revision under Project 2010-05.1
4	November 13, 2014	Adopted by NERC Board of Trustees	~~**Standad i**~~ Applicability ~~revised~~revision under Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources~~. n November 13, 2014 Project 2014-01~~
5		Adopted by NERC Board of Trustees	Revision under Project 2008-02.2

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[4] from Gerry Cauley, NERC President and CEO, dated January 7, 2011.

> "Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure. …Relays can misoperate, either operate when not needed or fail to operate when needed, for a number of reasons. First, the device could experience an internal failure – but this is rare. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies. Preventable errors can be introduced by field personnel and their supervisors or more programmatically by the organization."

The standard also addresses the findings in the *2011 Risk Assessment of Reliability Performance*[5]; July 2011.

> "…a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry."

The *State of Reliability 2014*[6] report continued to identify Protection System Misoperations as a significant contributor to automatic transmission outage severity. The report recommended completion of the development of PRC-004-3 as part of the solution to address Protection System Misoperations.

Definitions

The Misoperation definition is based on the IEEE/PSRC Working Group I3 "Transmission Protective Relay System Performance Measuring Methodology[7]." Misoperations of a Protection System include failure to operate, slowness in operating, or operating when not required either during a Fault or non-Fault condition.

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4 http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf

5 "2011 Risk Assessment of Reliability Performance." NERC. http://www.nerc.com/files/2011_RARPR_FINAL.pdf. July 2011. Pg. 3.

6 "State of Reliability 2014." NERC. http://www.nerc.com/pa/Stand/Pages/RelaibilityCoordinationProject20066.aspx. May 2014. Pg. 18 of 106.

7 "Transmission Protective Relay System Performance Measuring Methodology." Working Group I3 of Power System Relaying Committee of IEEE Power Engineering Society. 1999.

For reference, a "Protection System" is defined in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary") as:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

A BES interrupting device is a BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current. Although BES interrupting device mechanisms are not part of a Protection System, the standard uses the operation of a BES interrupting device by a Protection System to initiate the review for Misoperation.

The following two definitions are being proposed for inclusion in the NERC Glossary:

> **Composite Protection System –** *The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded.*

The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation.

Composite Protection System – Line Example

The Composite Protection System of the Alpha-Beta line (Circuit #123) is comprised of current differential, permissive overreaching transfer trip (POTT), step distance (classic zone 1, zone 2, and zone 3), instantaneous-overcurrent, time-overcurrent, out-of-step, and overvoltage protection. The protection is housed at the Alpha and Beta substations, and includes the associated relays, communications systems, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Transformer Example

The Composite Protection System of the Alpha transformer (#2) is comprised of internal differential, overall differential, instantaneous-overcurrent, and time-overcurrent protection. The protection is housed at the Alpha substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Generator Example

The Composite Protection System of the Beta generator (#3) is comprised of generator differential, overall differential, overcurrent, stator ground, reverse power, volts per hertz, loss-of-field, and undervoltage protection. The protection is housed at the Beta generating plant and at the Beta substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Breaker Failure Example

Breaker failure protection provides backup protection for the breaker, and therefore is part of the breaker's Composite Protection System. Considering breaker failure protection to be part of another Element's Composite Protection System could lead to an incorrect conclusion that a breaker failure operation automatically satisfies the "Slow Trip" criteria of the Misoperation definition.

- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. The breaker failure relaying operated because of a failed trip coil. The failed trip coil caused a Misoperation of the line's Composite Protection System.
- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. Only the breaker failure relaying operated because of a failed breaker mechanism. This was not a Misoperation because the breaker mechanism is not part of the breaker's Composite Protection System.
- An example of an "Unnecessary Trip – During Fault" is when the breaker failure relaying tripped at the same time as the line relaying during a Fault. The Misoperation was due to the breaker failure timer being set to zero.

Misoperation – *The failure a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:*

1. **Failure to Trip – During Fault** *– A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
2. ***Failure to Trip – Other Than Fault*** *– A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*

3. ***Slow Trip – During Fault*** *– A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
4. ***Slow Trip – Other Than Fault*** *– A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
5. ***Unnecessary Trip – During Fault*** *– An unnecessary Composite Protection System operation for a Fault condition on another Element.*
6. ***Unnecessary Trip – Other Than Fault*** *– An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.*

The Misoperation definition is based on the principle that an Element's total complement of protection is intended to operate dependably and securely.

- Failure to automatically reclose after a Fault condition is not included as a Misoperation because reclosing equipment is not included within the definition of Protection System.
- A breaker failure operation does not, in itself, constitute a Misoperation.
- A remote backup operation resulting from a "Failure to Trip" or a "Slow Trip" does not, in itself, constitute a Misoperation.

This proposed definition of Misoperation provides additional clarity over the current version. A Misoperation is the failure of a Composite Protection System to operate as intended for protection purposes. The definition includes six categories which provide further differentiation of what constitutes a Misoperation. These categories are discussed in greater detail in the following sections.

Failure to Trip – During Fault

This category of Misoperation typically results in the Fault condition being cleared by remote backup Protection System operation.

Example 1a: A failure of a transformer's Composite Protection System to operate for a transformer Fault is a Misoperation.

Example 1b: A failure of a "primary" transformer relay (or any other component) to operate for a transformer Fault is not a "Failure to Trip – During Fault" Misoperation as long as another component of the transformer's Composite Protection System operated.

Example 1c: A lack of target information does not by itself constitute a Misoperation. When a high-speed pilot system does not target because a high-speed zone element trips first, it would not in and of itself be a Misoperation.

Example 1d: A failure of an overall differential relay to operate is not a "Failure to Trip – During Fault" Misoperation as long as another component such as a generator differential relay operated.

Example 1e: The Composite Protection System for a bus does not operate during a bus Fault which results in the operation of all local transformer Protection Systems connected to that bus and all remote line Protection Systems connected to that bus isolating the faulted bus from the grid. The operation of the local transformer Protection Systems and the operation of all remote line Protection Systems correctly provided backup protection. There is one "Failure to Trip – During Fault" Misoperation of the bus Composite Protection System.

In analyzing the Protection System for Misoperation, the entity must also consider whether the "Slow Trip – During Fault" category applies to the operation.

Failure to Trip – Other Than Fault

This category of Misoperation may have resulted in operator intervention. The "Failure to Trip – Other Than Fault" conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Example 2a: A failure of a generator's Composite Protection System to operate for an unintentional loss of field condition is a Misoperation.

Example 2b: A failure of an overexcitation relay (or any other component) is not a "Failure to Trip – Other Than Fault" Misoperation as long as the generator's Composite Protection System operated as intended isolating the generator from the BES.

In analyzing the Protection System for Misoperation, the entity must also consider whether the "Slow Trip – Other Than Fault" category applies to the operation.

Slow Trip – During Fault

This category of Misoperation typically results in remote backup Protection System operation before the Fault is cleared.

Example 3a: A Composite Protection System that is slower than required for a Fault condition is a Misoperation if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. The current differential element of a multiple function relay failed to operate for a line Fault. The same relay's time-overcurrent element operated after a time delay. However, an adjacent line also operated from a time-overcurrent element. The faulted line's time-overcurrent element was found to be set to trip too slowly.

Example 3b: A failure of a breaker's Composite Protection System to operate as quickly as intended to meet the expected critical Fault clearing time for a line Fault in conjunction with a breaker failure (i.e., stuck breaker) is a Misoperation if it resulted in an unintended operation of at least one other Element's Composite Protection System. If a generating unit's Composite Protection System operates due to instability caused by the slow trip of the breaker's Composite Protection System, it is not an "Unnecessary Trip – During Fault" Misoperation of the generating unit's Composite Protection System. This event would be a "Slow Trip – During Fault" Misoperation of the breaker's Composite Protection System.

> **Example 3c:** A line connected to a generation interconnection station is protected with two independent high-speed pilot systems. The Composite Protection System for this line also includes step distance and time-overcurrent schemes in addition to the two pilot systems. During a Fault on this line, the two pilot systems fail to operate and the time-overcurrent scheme operates clearing the Fault with no generating units or other Elements tripping (i.e., no over-trips). This event is not a Misoperation.

The phrase “slower than required” means the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

The phrase “resulted in the operation of any other Composite Protection System” refers to the need to ensure that relaying operates in the proper or planned sequence (i.e., the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).

In analyzing the Protection System for Misoperation, the entity must also consider the “Unnecessary Trip – During Fault” category to determine if an “unnecessary trip” applies to the Protection System operation of an Element other than the faulted Element.

If a coordination error was at the local terminal (i.e., set too slow), then it was a "Slow Trip," category of Misoperation at the local terminal.

Slow Trip – Other Than Fault

The phrase “slower than required” means the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

> **Example 4:** A phase to phase fault occurred on the terminals of a generator. The generator's Composite Protection System and a transmission line's Composite Protection System both operated in response to the fault. It was found during subsequent investigation that the generator protection contained an inappropriate time delay. This caused the transmission line's correctly set overreaching zone of protection to operate. This was a Misoperation of the generator’s Composite Protection System, but not of the transmission line’s Composite Protection System.

The “Slow Trip – Other Than Fault” conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Unnecessary Trip – During Fault

An operation of a properly coordinated remote Protection System is not in and of itself a Misoperation if the Fault has persisted for a sufficient time to allow the correct operation of the Composite Protection System of the faulted Element to clear the Fault. A BES interrupting device failure, a "failure to trip" Misoperation, or a "slow trip" Misoperation may result in a proper remote Protection System operation.

> **Example 5:** An operation of a transformer's Composite Protection System which trips (i.e., over-trips) for a properly cleared line Fault is a Misoperation. The Fault is cleared properly by the faulted equipment's Composite Protection System (i.e., line relaying) without the need for an external Protection System operation resulting in an unnecessary trip of the transformer protection; therefore, the transformer Protection System operation is a Misoperation.
>
> **Example 5b:** An operation of a line's Composite Protection System which trips (i.e., over-trips) for a properly cleared Fault on a different line is a Misoperation. The Fault is cleared properly by the faulted line's Composite Protection System (i.e., line relaying); however, elsewhere in the system, a carrier blocking signal is not transmitted (e.g., carrier ON/OFF switch found in OFF position) resulting in the operation of a remote Protection System, single-end trip of a non-faulted line. The operation of the Protection System for the non-faulted line is an unnecessary trip during a Fault. Therefore, the non-faulted line Protection System operation is an "Unnecessary Trip – During Fault" Misoperation.
>
> **Example 5c:** If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip – During Fault" category of Misoperation at the remote terminal.

Unnecessary Trip – Other Than Fault

Unnecessary trips for non-Fault conditions include but are not limited to: power swings, overexcitation, loss of excitation, frequency excursions, and normal operations.

> **Example 6a:** An operation of a line's Composite Protection System due to a relay failure during normal operation is a Misoperation.
>
> **Example 6b:** Tripping a generator by the operation of the loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation assuming the Composite Protection System was not intended to operate under this condition.
>
> **Example 6c:** An impedance line relay trip for a power swing that entered the relay's characteristic is a Misoperation if the power swing was stable and the relay operated because power swing blocking was enabled and should have prevented the trip, but did not.
>
> **Example 6d:** Tripping a generator operating at normal load by the operation of a reverse power protection relay due to a relay failure is a Misoperation.

Additionally, an operation that occurs during a non-Fault condition but was initiated directly by on-site (i.e., real-time) maintenance, testing, inspection, construction, or commissioning is not a Misoperation.

> **Example 6e:** A BES interrupting device operation that occurs at the remote end of a line during a non-Fault condition because a direct transfer trip was initiated by system maintenance and testing activities at the local end of the line is not a Misoperation because of the maintenance exclusion in category 6 of the definition of "Misoperation."

The "on-site" activities at one location that initiates a trip to another location are included in this exemption. This includes operation of a Protection System when energizing equipment to facilitate measurements, such as verification of current circuits as a part of performing commissioning; however, once the maintenance, testing, inspection, construction, or commissioning activity associated with the Protection System is complete, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of on-site personnel.

Special Cases

Protection System operations for these cases would not be a Misoperation.

> **Example 7a:** A generator Protection System operation prior to closing the unit breaker(s) is not a Misoperation provided no in-service Elements are tripped.

This type of operation is not a Misoperation because the generating unit is not synchronized and is isolated from the BES. Protection System operations that occur when the protected Element is out of service and that do not trip any in-service Elements are not Misoperations.

In some cases where zones of protection overlap, the owner(s) of Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element.

> **Example 7b:** The high-side of a transformer connected to a line may be within the zone of protection of the supplying line's relaying. In this case, the line relaying is planned to protect the area of the high-side of the transformer and into its primary winding. In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for Faults on the high-side of the connected transformer. Therefore, the operation of the line relaying for a high-side transformer Fault operated as intended and would not be a Misoperation.

Below are examples of conditions that would be a Misoperation.

> **Example7c:** A 230 kV shunt capacitor bank was released for operational service. The capacitor bank trips due to a settings error in the capacitor bank differential relay upon energization.
>
> **Example 7d:** A 230/115 kV BES transformer bank trips out when being re-energized due to an incorrect operation of the transformer differential relay for inrush after being released for operational service. Only the high-side breaker opens since the low-side breaker had not yet been closed.

Non-Protective Functions

BES interrupting device operations which are initiated by non-protective functions, such as those associated with generator controls, excitation controls, or turbine/boiler controls, static voltampere-reactive compensators (SVC), flexible ac transmission systems (FACTS), high-voltage dc (HVdc) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. The standard is not applicable to non-protective functions such as automation (e.g., data collection) or control functions that are embedded within a Protection System.

Control Functions

The entity must make a determination as to whether the standard is applicable to each operation of its Protection System in accordance with the provided exclusions in the standard's Applicability, see Section 4.2.1. The subject matter experts (SME) developing this standard recognize that entities use Protection Systems as part of a routine practice to control BES Elements. This standard is not applicable to operation of protective functions within a Protection System when intended for controlling a BES Element as a part of an entity's process or planned switching sequence. The following are examples of conditions to which this standard is not applicable:

> **Example 8a:** The reverse power protective function that operates to remove a generating unit from service using the entity's normal or routine process.
>
> **Example 8b:** The reverse power relay enables a permissive trip and the generator operator trips the unit.

The standard is not applicable to operation of the protective relay because its operation is intended as a control function as part of a controlled shutdown sequence for the generator. However, the standard remains applicable to operation of the reverse power relay when it operates for conditions not associated with the controlled shutdown sequence, such as a motoring condition caused by a trip of the prime mover.

The following is another example of a condition to which this standard is not applicable:

> **Example 8c:** Operation of a capacitor bank interrupting device for voltage control using functions embedded within a microprocessor based relay that is part of a Protection System.

The above are examples only, and do not constitute an all-inclusive list to which the standard is not applicable.

Extenuating Circumstances

In the event of a natural disaster or other extenuating circumstances, the December 20, 2012 Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, reads: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." The Regional Entities to whom NERC has delegated

authority will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.

The volume of Protection System operations tend to be sporadic. If a high rate of Protection System operations is not sustained, utilities will have an opportunity to catch up within the 120 day period.

Requirement Time Periods

The time periods within all the Requirements are distinct and separate. The applicable entity in Requirement R1 has 120 calendar days to identify whether a BES interrupting device operation is a Misoperation. Once the applicable entity has identified a Misoperation, it has completed its performance under Requirement R1. Identified Misoperations without an identified cause become subject to Requirement R4 and any subsequent Requirements as necessary. Identified Misoperations with an identified cause become subject to Requirement R5 and any subsequent Requirements as necessary.

In Requirement R2, the applicable entity has 120 calendar days, based on the date of the BES interrupting device operation, to provide notification to the other Protection System owners that meet the circumstances in Parts 2.1 and 2.2. For the case of an applicable entity that was notified (R3), it has the later of 120 calendar days from the date of the BES interrupting device operation or 60 calendar days of notification to identify whether its Protection System components caused a Misoperation.

Once a Misoperation is identified in either Requirement R1 or R3, and the applicable entity did not identify the cause(s) of the Misoperation, the time period for performing at least one investigative action every two full calendar quarters begins. The time period(s) in Requirement R4 resets upon each period. When the applicable entity's investigative actions identify the cause of the identified Misoperation or the applicable entity declares that no cause was found, the applicable entity has completed its performance in Requirement R4.

The time period in Requirement R5 begins when the Misoperation cause is first identified. The applicable entity is allotted 60 calendar days to perform one of the two activities listed in Requirement R5 (e.g., CAP or declaration) to complete its performance under Requirement R5.

Requirement R6 time period is determined by the actions and the associated timetable to complete those actions identified in the CAP. The time periods contained in the CAP may change from time to time and the applicable entity is required to update the timetable when it changes.

Time periods provided in the Requirements are intended to provide a reasonable amount of time to perform each Requirement. Performing activities in the least amount of time facilitates prompt identification of Misoperations, notification to other Protection System owners, identification of the cause(s), correction of the cause(s), and that important information is retained that may be lost due to time.

Requirement R1

This Requirement initiates a review of each BES interrupting device operation to identify whether or not a Misoperation may have occurred. Since the BES interrupting device owner typically monitors and tracks device operations, the owner is the logical starting point for identifying Misoperations of Protection Systems for BES Elements. A review is required when (1) a BES interrupting device operates that is caused by a Protection System or by manual intervention in response to a Protection System failure to operate, (2) regardless of whether the owner owns all or part of the Protection System component(s), and (3) the owner identified its Protection System component(s) as causing the BES interrupting device operation or was caused by manual intervention in response to its Protection System failure to operate.

Since most Misoperations result in the operation of one or more BES interrupting devices, these operations initiate a review to identify any Misoperation. If an Element is manually isolated in response to a failure to operate, the manual isolation of the Element triggers a review for Misoperation.

> **Example R1a:** The failure of a loss of field relay on a generating unit where an operator takes action to isolate the unit.

Manual intervention may indicate a Misoperation has occurred, thus requiring the initiation of an investigation by the BES interrupting device owner.

For the case where a BES interrupting device did not operate and remote clearing occurs due to the failure of a Composite Protection System to operate, the BES interrupting device owner would still review the operation under Requirement R1. However, if the BES interrupting device owner determines that its Protection System component operated as backup protection for a condition on another entity's BES Element, the owner would provide notification of the operation to the other Protection System owner(s) under Requirement R2, Part 2.2.

Protection Systems are made of many components. These components may be owned by different entities. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner's differential relay. All of these components and many more are part of a Protection System. It is expected that all of the owners will communicate with each other, sharing information freely, so that Protection System operations can be analyzed, Misoperations identified, and corrective actions taken.

Each entity is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation regardless of the level of ownership. A combination of available information from resources such as counters, relay targets, Supervisory Control and Data Acquisition (SCADA) systems, or DME would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation. The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether its Protection System component(s) caused a Misoperation.

The Protection System operation may be documented in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System.

Repeated operations which occur during the same automatic reclosing sequence do not need a separate identification under Requirement R1. Repeated Misoperations which occur during the same 24-hour period do not need a separate identification under Requirement R1. This is consistent with the NERC *Misoperations Report*[8] which states:

> "In order to avoid skewing the data with these repeated events, the NERC SPCS should clarify, in the next annual update of the misoperation template, that all misoperations due to the same equipment and cause within a 24 hour period be recorded as one misoperation."

The following is an example of a condition that is not a Misoperation.

> **Example R1b:** A high impedance Fault occurs within a transformer. The sudden pressure relaying detects and operates for the Fault, but the differential relaying did not operate due to the low Fault current levels. This is not a Misoperation because the Composite Protection System was not required to operate because the Fault was cleared by the sudden pressure relay.

Requirement R2

Requirement R2 ensures notification of those who have a role in identifying Misoperations, but were not accounted for within Requirement R1. In the case of multi-entity ownership, the entity that owns the BES interrupting device that operated is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation under Requirement R1; however, if the entity that owns a BES interrupting device determines that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation, it must notify the other Protection System owner(s) that share Misoperation identification responsibility when the criteria in Requirement R2 is met.

This Requirement does not preclude the Protection System owners from initially communicating and working together to determine whether a Misoperation occurred and, if so, the cause. The BES interrupting device owner is only required to officially notify the other owners when it: (1) shares the Composite Protection System ownership with other entity(ies), (2) determines that a Misoperation occurred or cannot rule out a Misoperation, and (3) determines its Protection System component(s) did not cause a Misoperation or is unsure. Officially notifying the other owners without performing a preliminary review may unnecessarily burden the other owners with compliance obligations under Requirement R3, redirect valuable resources, and add little benefit to reliability. The BES interrupting device owner should officially notify other owners when appropriate within the established time period.

[8] "Misoperations Report." Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. April 1, 2013. pg. 37 of 40.

The following is an example of a notification to another Protection System owner:

> **Example R2a:** Circuit breakers A and B at the Charlie station tripped from directional comparison blocking (DCB) relaying on 03/03/2014 at 15:43 UTC during an external Fault. As discussed last week, the fault records indicate that a problem with your equipment (failure to transmit) caused the operation.
>
> **Example R2b:** A generator unit tripped out immediately upon synchronizing to the grid due to a Misoperation of its overcurrent protection. The Transmission Owner owns the 230 kV generator breaker that operated. The Transmission Owner, as the owner of the BES interrupting device after determining that its Protection System components did not cause the Misoperation, notified the Generator Owner of the operation. The Generator Owner investigated and determined that its Protection System components caused the Misoperation. In this example, the Generator Owner's Protection System components did cause the Misoperation. As the owner of the Protection System components that caused the Misoperation, the Generator Owner is responsible for creating and implementing the CAP.

A Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the notification criteria in Part 2.1.1 of Requirement R2. For example, if the same personnel within a registered entity perform the Misoperation identification for both the Generator Owner and Transmission Owner functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be covered in Requirement R1.

> **Example R2c:** Line A Composite Protection System (owned by entity 1) failed to operate for an internal Fault. As a result, the zone 3 portion of Line B's Composite Protection System (owned by entity 2) and zone 3 portion of Line C's Composite Protection System (owned by entity 3) operated to clear the Fault. Entity 2 and 3 notified entity 1 of the remote zone 3 operation.

For the case where a BES interrupting device operates to provide backup protection for a non-BES Element, the entity reviewing the operation is not required to notify the other owners of Protection Systems for non-BES Elements. No notification is required because this Reliability Standard is not applicable to Protection Systems for non-BES Elements.

Requirement R3

For Requirement R3 (i.e., notification received), the entity that also owns a portion of the Composite Protection System is expected to use judgment to identify whether the Protection System operation is a Misoperation. A combination of available information from resources such as counters, relay targets, SCADA, DME, and information from the other owner(s) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. The entity may decide to identify the operation as a

Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation.

The entity that is notified by the BES interrupting device owner is allotted the later of 60 calendar days from receipt of notification or 120 calendar days from the BES interrupting device operation date to determine if its portion of the Composite Protection System caused the Protection System operation. It is expected that in most cases of a jointly owned Protection System, the entity making notification would have been in communication with the other owner(s) early in the process. This means that the shorter 60 calendar days only comes into play if the notification occurs in the second half of the 120 calendar days allotted to the BES interrupting device owner in Requirement R1.

The Protection System review may be organized in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System. The BES interrupting device owner's notification received may be documented in a variety of ways such as an email or a facsimile.

Requirement R4

The entity in Requirement R4 (i.e., cause identification), whether it is the entity that owns the BES interrupting device or an entity that was notified, is expected to use due diligence in taking investigative action(s) to determine the cause(s) of an identified Misoperation for its portion of the Composite Protection System. The SMEs developing this standard recognize there will be cases where the cause(s) of a Misoperation will not be revealed during the allotted time periods in Requirements R1 or R3; therefore, Requirement R4 provides the entity a mechanism to continue its investigative work to determine the cause(s) of the Misoperation when the cause is not known.

A combination of available information from resources such as counters, relay targets, SCADA, DME, test results, and studies would typically be used to determine the cause of the Misoperation. At least one investigative action must be performed every two full calendar quarters until the investigation is completed.

The following is an example of investigative actions taken to determine the cause of an identified Misoperation:

> **Example R4a**: A Misoperation was identified on 03/18/2014. A line outage to test the Protection System was scheduled on 03/24/2014 for 12/15/2014 as the first investigative action (i.e., beyond the next two full calendar quarters) due to summer peak conditions. The protection engineer contacted the manufacturer on 04/10/2014 (i.e., within two full calendar quarters) to obtain any known issues. The engineer reviewed manufacturer's documents on 05/27/2014. The outage schedule was confirmed on 08/29/2014 and was taken on 12/15/2014. Testing was completed on 12/16/2014 (i.e., in the second two full quarters) revealing the microprocessor relay as the cause of the Misoperation. A CAP is being developed to replace the relay.

Periodic action minimizes compliance burdens and focuses the entity's effort on determining the cause(s) of the Misoperation while providing measurable evidence. The SMEs recognize that

certain planned investigative actions may require months or years to schedule and complete; therefore, the entity is only required to perform at least one investigative action every two full calendar quarters. If an investigative action is performed in the first quarter of a calendar year, the next investigative action would need to be performed by the end of the third calendar quarter. If an investigative action is performed in the last quarter of a calendar year, the next investigative action would need to be performed by the end of the second calendar quarter of the following calendar year. Investigative actions may include a variety of actions, such as reviewing DME records, performing or reviewing studies, completing relay calibration or testing, requesting manufacturer review, requesting an outage, or confirming a schedule.

The entity's investigation is complete when it identifies the cause of the Misoperation or makes a declaration that no cause was determined. The declaration is intended to be used if the entity determines that investigative actions have been exhausted or have not provided direction for identifying the Misoperation cause. Historically, approximately 12% of Misoperations are unknown or unexplainable.[9]

Although the entity only has to document its specific investigative actions taken to determine the cause(s) of an identified Misoperation, the entity should consider the benefits of formally organizing (e.g., in a report or database) its actions and findings. Well documented investigative actions and findings may be helpful in future investigations of a similar event or circumstances. A thorough report or database may contain a detailed description of the event, information gathered, investigative actions, findings, possible causes, identified causes, and conclusions. Multiple owners of a Composite Protection System might consider working together to produce a common report for their mutual benefit.

The following are examples of a declaration where no cause was determined:

> **Example R4b**: A Misoperation was identified on 04/11/2014. All relays at station A and B functioned properly during testing on 08/26/2014 as the first investigative action. The carrier system functioned properly during testing on 08/27/2014. The carrier coupling equipment functioned properly during testing on 08/28/2014. A settings review completed on 09/03/2014 indicated the relay settings were proper. Since the equipment involved in the operation functioned properly during testing, the settings were reviewed and found to be correct, and the equipment at station A and station B is already monitored. The investigation is being closed because no cause was found.
>
> **Example R4c:** A Misoperation was identified on 03/22/2014. The protection scheme was replaced before the cause was identified. The power line carrier or PLC based protection was replaced with fiber-optic based protection with an in-service date of 04/16/2014. The new system will be monitored for recurrence of the Misoperation.

Requirement R5

Resolving the causes of Protection System Misoperations benefits BES reliability by preventing recurrence. The Corrective Action Plan (CAP) is an established tool for resolving operational problems. The NERC Glossary defines a Corrective Action Plan as, *"A list of actions and an*

[9] NERC System Protection and Control Subcommittee. Misoperations Report. April 1, 2013: http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. Figure 15: NERC Wide Misoperations by Cause Code. pg. 22 of 40.

associated timetable for implementation to remedy a specific problem." Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the Misoperation cause is identified in Requirement R1, R3 or R4, Requirement R5 requires Protection System owner(s) to develop a CAP, or explain why corrective actions are beyond the entity's control or would not improve BES reliability. The entity must develop the CAP or make a declaration why additional actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken within 60 calendar days of first determining a cause.

The SMEs developing this standard recognize there may be multiple causes for a Misoperation. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple CAP(s) to correct multiple causes of a Misoperation. The 60 calendar day period for developing a CAP (or declaration) is established on the basis of industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent Misoperation recurrence, the timetable for executing such actions, and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. The evaluation of these other Protection Systems aims to reduce the risk and likelihood of similar Misoperations in other Protection Systems. The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection Systems at other locations or the reasoning for not taking any action. The CAP and an evaluation of other Protection Systems including other locations must be developed to complete Requirement R5.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined capacitor replacement was not necessary.

For completion of each CAP in Examples R5a through R5d, please see Examples R6a through R6d.

> **Example R5a:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay has not been experiencing problems and is systematically being replaced with microprocessor relays as Protection Systems are modernized. Therefore, it was assessed that a program for wholesale preemptive replacement of capacitors in this type of impedance relay does not need to be established for the system.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5b:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, a program should be established by 12/01/2014 for wholesale preemptive replacement of capacitors in this type of impedance relay.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5c:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, the preemptive replacement of capacitors in this type of impedance relay should be pursued for the identified stations A through I by 04/30/2015.
>
> A plan is being developed to replace the impedance relay capacitors at stations A, B, and C by 09/01/2014. A second plan is being developed to replace the impedance relay capacitors at stations D, E, and F by 11/01/2014. The last plan will replace the impedance relay capacitors at stations G, H, and I by 02/01/2015.

The following is an example of a CAP for a relay Misoperation that was due to a version 2 firmware problem and the evaluation of the cause at similar locations which determined the firmware needs preemptive correction action.

> **Example R5d:** Actions: Provide the manufacturer fault records. Install new firmware pending manufacturer results by 10/01/2014.
>
> Applicability to other Protection Systems: Based on the evaluation of other locations and a risk assessment, the newer firmware version 3 should be installed at all installations that are identified to be version 2. Twelve relays were identified across the system. Proposed completion date is 12/31/2014.

The following are examples of a declaration made where corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken.

> **Example R5e:** The cause of the Misoperation was due to a non-registered entity communications provider problem.
>
> **Example R5f:** The cause of the Misoperation was due to a transmission transformer tapped industrial customer who initiated a direct transfer trip to a registered entity's transmission breaker.

In situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity's control.

The following are examples of declarations made why corrective actions would not improve BES reliability.

> **Example R5g:** The investigation showed that the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations.
>
> **Example R5h:** As a result of an operation that left a portion of the power system in an electrical island condition, circuit XYZ within that island tripped, resulting in loss of load within the island. Subsequent investigation showed an overfrequency condition persisted after the formation of that island and the XYZ line protective relay operated. Since this relay was operating outside of its designed frequency range and would not be subject to this condition when line XYZ is operated normally connected to the BES, no corrective action will be taken because BES reliability would not be improved.
>
> **Example R5i:** During a major ice storm, four of six circuits were lost at Station A. Subsequent to the loss of these circuits, a skywire (i.e., shield wire) broke near station A on line AB (between Station A and B) resulting in a phase-phase Fault. The protection scheme utilized for both protection groups is a permissive overreaching transfer trip (POTT). The Line AB protection at Station B tripped timed for this event (i.e., Slow Trip – During Fault) even though this line had been identified as requiring high speed clearing. A weak infeed condition was created at Station A due to the loss of 4 transmission circuits resulting in the absence of a permissive signal on Line AB from Station A during this Fault. No corrective action will be taken for this Misoperation as even under N-1 conditions, there is normally enough infeed at Station A to send a proper permissive signal to station B. Any changes to the protection scheme to account for this would not improve BES reliability.

A declaration why corrective actions are beyond the entity's control or would not improve BES reliability should include the Misoperation cause and the justification for taking no corrective action. Furthermore, a declaration that no further corrective actions will be taken is expected to be used sparingly.

Requirement R6

To achieve the stated purpose of this standard, which is to identify and correct the causes of Misoperations of Protection Systems for BES Elements, the responsible entity is required to implement a CAP that addresses the specific problem (i.e., cause(s) of the Misoperation) through completion. Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until completed. Accomplishing this objective is intended to reduce the occurrence of future Misoperations of a similar nature, thereby improving reliability and minimizing risk to the BES.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip (See also, Example R5a).

> **Example R6a:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> CAP completed on 06/25/2014.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip that resulted in the correction and the establishment of a program for further replacements (See also, Example R5b).

> **Example R6b:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> A program for wholesale preemptive replacement of capacitors in this type of impedance relay was established on 10/28/2014.
>
> CAP completed on 10/28/2014.

The following is an example of a completed CAP of corrective actions with a timetable that required updating for a failed relay and preemptive actions for similar installations (See also, Example R5c).

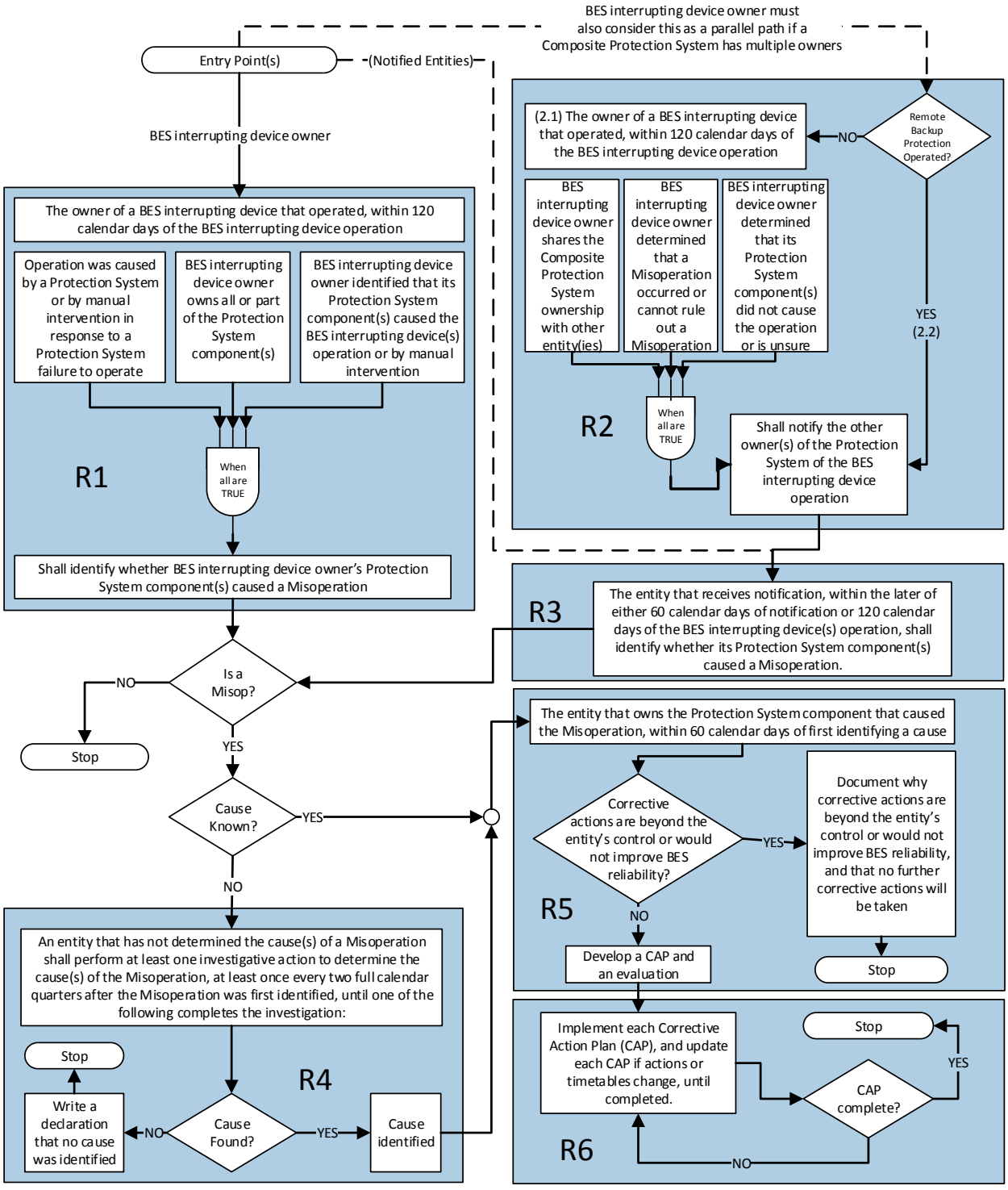
> **Example R6c:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> The impedance relay capacitor replacement was completed at stations A, B, and C on 08/16/2014. The impedance relay capacitor replacement was completed at stations D, E, and F on 10/24/2014. The impedance relay capacitor replacement for stations G, H, and I were postponed due to resource rescheduling from a scheduled 02/01/15 completion to 04/01/2015 completion. Capacitor replacement was completed on 03/09/2015 at stations G, H, and I. All stations identified in the evaluation have been completed.
>
> CAP completed on 03/09/2015.

The following is an example of a completed CAP for corrective actions with updated actions for a firmware problem and preemptive actions for similar installations. (See also, Example R5d).

> **Example R6d:** Actions: fault records were provided to the manufacturer on 06/04/2014. The manufacturer responded that the Misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 08/12/2014.
>
> Nine of the twelve relays were updated to version 3 firmware on 09/23/2014. The manufacturer provided a subsequent update which was determined to be beneficial for the remaining relays. The remaining three of twelve relays identified as having the version 2 firmware were updated to version 3.01 firmware on 11/10/2014.
>
> CAP completed on 11/10/2014.

The CAP is complete when all of the actions identified within the CAP have been completed.

Process Flow Chart: Below is a graphical representation demonstrating the relationships between Requirements:



Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Introduction:

The only revisions made to this version of PRC-004-4 are revisions to section 4.2 Facilities to clarify applicability of the Requirements of the standard at generator Facilities. These applicability revisions are intended to clarify and provide for consistent application of the Requirements to BES generator Facilities included in the BES through Inclusion I4 – Dispersed Power Producing Resources.

The DGR version of this standard had been labeled PRC-004-4 for balloting purposes. The 'X' had indicated that a version number would be applied at a later time, because multiple versions of PRC-004 were in development at the time of the previous posting. The 'X' designation reflected the fact that applicability changes need to apply to versions of the standard that are approved (PRC-004-2.1a) and in development in Project 2010-05.1. However, PRC-004-3 was approved by the NERC Board of Trustees on August 14, 2014, so this version has been designated PRC-004-4 to indicate that this version is the successor version.

Rationale for Applicability:

Misoperations occurring on the Protection Systems of individual generation resources identified under Inclusion I4 of the BES definition do not have a material impact on BES reliability when considered individually; however, the aggregate capability of these resources may impact BES reliability if a number of Protection Systems on the individual power producing resources incorrectly operated or failed to operate as designed during a system event. To recognize the potential for the Protection Systems of individual power producing resources to affect the reliability of the BES, 4.2.1.5 of the Facilities section reflects the threshold consistent with the revised BES definition. See FERC Order Approving Revised Definition, P 20, Docket No. RD14-2-000. The intent of 4.2.1.5 of the Facilities section is to exclude from the standard requirements these Protection Systems for "common- mode failure" type scenarios affecting less than or equal to 75 MVA aggregated nameplate generating capability at these dispersed generating facilities.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

PRC-010-2 – Undervoltage Load Shedding

Project 2008-02.2 – Phase 2 UVLS: Misoperations

Requested Approvals

- PRC-010-2 – Undervoltage Load Shedding

Requested Retirements

- PRC-010-1 – Undervoltage Load Shedding[1]

Prerequisite Approvals

- PRC-004-5 — Protection System Misoperation Identification and Correction

General Considerations

The implementation period is intended to align with the Effective Date of PRC-010-1 or occur soon thereafter in order to incorporate certain aspects of PRC-022-1 – Under-Voltage Load Shedding Program Performance into PRC-004. PRC-022-1 was retired by PRC-010-1. The Implementation Plan for PRC-010-1[2] allows twelve (12) calendar months after applicable approvals. Version five of PRC-004 is including undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

Applicable Entities

- Planning Coordinator
- Transmission Planner
- Undervoltage load shedding (UVLS) entities – Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator

[1] PRC-010-1 was adopted by the NERC Board of Trustees on November 13, 2014.

[2] Refer to Project 2008-02.2 on the NERC website. (http://www.nerc.com/pa/Stand/Pages/Project-2008-02_2-Phase-2-Undervoltage-Load-Shedding-UVLS-Misoperations.aspx)

Effective Dates

PRC-010-2 shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The NERC Board of Trustees adopted PRC-010-1 on November 13, 2014.
2. The NERC Standards Committee authorized the initial posting on February 18, 2015.

Description of Current Draft

The UVLSSDT is posting Draft 1 of PRC-010-2 – Undervoltage Load Shedding for a 45-day initial formal comment period and concurrent/parallel initial ballot in the last ten days of the comment period. The draft contains revisions to Requirements R4 and R5 to address UVLS equipment.

Anticipated Actions	Date
45-day formal comment period with ballot	February 2015
10-day final ballot	April 2015
Board adoption	May 2015

Project Development Background

The undervoltage load shedding (UVLS) standard drafting team (SDT) was tasked with addressing Misoperation of UVLS equipment during the development of version one of PRC-010 and version three of PRC-004 in Project 2010-05.1 (i.e., Misoperation). This project has been named phase 2 of Project 2008-02 (i.e., UVLS) for clarity purposes. Each SDT for these two projects outlined work necessary to address Misoperation of UVLS equipment. This work was deferred, at the time, because both PRC-010-1 and PRC-004-3 contained dependencies with other projects requiring their completion. This phase two is a continuation of the work performed under the Standards Authorization Request (SAR) for Project 2008-02.

The revisions proposed in Reliability Standard PRC-010-2 meet the following objectives:

- Address the UVLS Misoperation the remaining work due to the retirement of PRC-022-1 (Undervoltage Load Shedding Program Performance) during the development of PRC-010-1 (Undervoltage Load Shedding)
- Ensure UVLS equipment (i.e., operation or non-operation) within the UVLS Program is assessed and mitigated

Basis for Revision

Originally, Misoperation of UVLS equipment was planned to be appended to a future version of PRC-004 (Protection System Misoperation Identification and Correction). The SDT is proposing a two-prong approach by revising both PRC-004 and PRC-010 to address the concern of identifying Misoperations of UVLS equipment in PRC-022-1.

First, the SDT proposes an addition to the Applicability section of PRC-004 to include UVLS that is intended to trip one or more Bulk Electric System (BES) Elements. This is consistent with previous communication to industry about addressing Misoperation of UVLS equipment. Entities will be required to address UVLS that trips a BES Element similarly to other Protection Systems in PRC-004. While the revision to PRC-004 consistent with the communicated approach, the SDT determined that the proposed revision fails to address the performance (operation or non-operations) of UVLS Program equipment not covered by the strict processes of PRC-004.

Second, the SDT is proposing clarifying revisions in PRC-010-2, Requirements R4 and R5 to address UVLS Program equipment performance. These revisions are not requiring UVLS entities to address UVLS protective relays not covered by the strict processes of PRC-004; however, PRC-010-2 is requiring UVLS entities to address the deficiencies (e.g., Misoperations) identified in the assessment performed by Planning Coordinator or Transmission Planner in Requirement R4. Deficiencies include the performance (operation or non-operation) issues of UVLS Program equipment. These deficiencies, if any, are addressed by the UVLS entities through a Corrective Action Plan (CAP) developed in Requirement R5 and executed by the UVLS entities in Requirement R2 of PRC-010.

The term “Misoperation” as defined by the Glossary of Terms Used in NERC Reliability Standards is not used within the Requirements of PRC-010; however, the term is used in the Guidelines and Technical Basis section of the standard to provide clarity that UVLS Program equipment deficiencies include Misoperations that are to be corrected by UVLS entities. The PRC-010-2 Reliability Standard mandates that UVLS entities are to correct the deficiencies identified by the Planning Coordinator or Transmission Planner, such as Misoperation of UVLS equipment. Deficiencies are identified through either the periodic assessment or an assessment performed following an event and included in a CAP to the UVLS entity. The structure used by the SDT allows the Planning Coordinator and Transmission Planner to assess UVLS equipment for Misoperation under PRC-010 rather than the Generator Owner, Transmission Owner, and Distribution Provider applicable to the strict processes of PRC-004.

The two-pronged approach ensures that any UVLS Program equipment containing a deficiency is identified and corrected under PRC-010 and UVLS that trips a BES Element under is corrected under PRC-004 to address the requirements in the retired PRC-022-1.

When this standard receives Board adoption, the rationale boxes in the Supplemental Material section of the standard will remain. The rationale box for Requirement R5 will be removed.

A. Introduction

1. **Title:** Undervoltage Load Shedding
2. **Number:** PRC-010-2
3. **Purpose:** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Coordinator.

   4.1.2 Transmission Planner.

   4.1.3 Undervoltage load shedding (UVLS) entities – Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator.

5. **Effective Date:** See Project 2008-02.2 Implementation Plan.

B. Requirements and Measures

R1. Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS Program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design.

1.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M1. Acceptable evidence may include, but is not limited to, date-stamped studies and analyses, reports, or other documentation detailing the effectiveness of the UVLS Program, and date-stamped communications showing that the UVLS Program specifications and implementation schedule were provided to UVLS entities.

R2. Each UVLS entity shall adhere to the UVLS Program specifications and implementation schedule determined by its Planning Coordinator or Transmission Planner associated

with UVLS Program development per Requirement R1 or with any Corrective Action Plans per Requirement R5. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Acceptable evidence must include date-stamped documentation on the completion of actions and may include, but is not limited to, identifying the equipment armed with UVLS relays, the UVLS relay settings, associated Load summaries, work management program records, work orders, and maintenance records.

R3. Each Planning Coordinator or Transmission Planner shall perform a comprehensive assessment to evaluate the effectiveness of each of its UVLS Programs at least once every 60 calendar months. Each assessment shall include, but is not limited to, studies and analyses that evaluate whether: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. The UVLS Program resolves the identified undervoltage issues for which the UVLS Program is designed.

3.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M3. Acceptable evidence may include, but is not limited to, date-stamped reports or other documentation detailing the assessment of the UVLS Program.

Rationale for Requirement R4: Refer to the Supplemental Section at the end of the document for the rationale.

R4. Each Planning Coordinator or Transmission Planner shall, within 12 calendar months of an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, perform an assessment to evaluate: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Whether its UVLS Program resolved the undervoltage issues associated with the event, and

4.2. The performance (i.e., operation and non-operation) of the UVLS Program equipment.

M4. Acceptable evidence may include, but is not limited to, date-stamped event data, event analysis reports, or other documentation detailing the assessment of the UVLS Program and associated equipment.

R5. Each Planning Coordinator or Transmission Planner that identifies deficiencies during an assessment performed in either Requirement R3 or R4 shall develop a Corrective Action Plan to address the deficiencies and subsequently provide the Corrective Action Plan, including an implementation schedule, to UVLS entities within three

calendar months of completing the assessment. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Acceptable evidence must include a date-stamped Corrective Action Plan that addresses identified deficiencies and may also include date-stamped reports or other documentation supporting the Corrective Action Plan. Evidence should also include date-stamped communications showing that the Corrective Action Plan and an associated implementation schedule were provided to UVLS entities.

R6. Each Planning Coordinator that has a UVLS Program in its area shall update a database containing data necessary to model the UVLS Program(s) in its area for use in event analyses and assessments of the UVLS Program at least once each calendar year. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. Acceptable evidence may include, but is not limited to, date-stamped spreadsheets, database reports, or other documentation demonstrating a UVLS Program database was updated.

R7. Each UVLS entity shall provide data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of a UVLS Program database. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M7. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating data was provided to the Planning Coordinator as specified.

R8. Each Planning Coordinator that has a UVLS Program in its area shall provide its UVLS Program database to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of a written request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M8. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating that the UVLS Program database was provided within 30 calendar days of receipt of a written request.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For

instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Planning Coordinator, Transmission Planner, Distribution Provider, and Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The applicable entity shall retain documentation as evidence for six calendar years.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

"Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	High	N/A	N/A	N/A	The applicable entity that developed the UVLS Program failed to evaluate the program's effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to UVLS entities in accordance with Requirement R1, including the items specified in Parts 1.1 and 1.2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Long-term Planning	High	N/A	N/A	The applicable entity failed to adhere to the UVLS Program specifications in accordance with Requirement R2. OR The applicable entity failed to adhere to the implementation schedule in accordance with Requirement R2.	The applicable entity failed to adhere to the UVLS Program specifications and implementation schedule in accordance with Requirement R2.
R3	Long-term Planning	Medium	N/A	N/A	N/A	The applicable entity failed to perform an assessment at least once during the 60 calendar months in accordance with Requirement R3, including the items specified in Parts 3.1 and 3.2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Medium	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 12 calendar months but less than or equal to 13 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 13 calendar months but less than or equal to 14 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 14 calendar months but less than or equal to 15 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 15 calendar months after an applicable event. OR The applicable entity failed to perform an assessment in accordance with Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning	Medium	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by less than or equal to 15 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 15 calendar days but less than or equal to 30 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 30 calendar days but less than or equal to 45 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 45 calendar days. OR The responsible entity failed to develop a Corrective Action Plan or provide it to UVLS entities in accordance with Requirement R5.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	Operations Planning	Lower	The applicable entity updated the database in accordance with Requirement R6 but was late by less than or equal to 30 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 60 calendar days but less than or equal to 90 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 90 calendar days. OR The applicable entity failed to update the database in accordance with Requirement R6.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	Operations Planning	Lower	The applicable entity provided data in accordance with Requirement R7 but was late by less than or equal to 30 calendar days per the specified schedule. OR The applicable entity provided data in accordance with Requirement R7 but the data was not provided according to the specified format.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 30 calendar days but less than or equal to 60 calendar days per the specified schedule.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 60 calendar days but less than or equal to 90 calendar days per the specified schedule.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 90 calendar days per the specified schedule. OR The applicable entity failed to provide data in accordance with Requirement R7.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	Operations Planning	Lower	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by less than or equal to 15 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 15 calendar days but less than or equal to 30 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 30 calendar days but less than or equal to 45 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 45 calendar days. OR The applicable entity failed to provide its UVLS Program database in accordance with Requirement R8.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	
0	April 1, 2005	Effective Date	
0	February 7, 2013	Adopted by NERC Board of Trustees	R2 and associated elements for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.
1	November 13, 2014	Adopted by NERC Board of Trustees	Revisions made under Project 2008-02: Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS) to address directive issued in FERC Order No. 763.
2		Adopted by NERC Board of Trustees	Revisions made under Project 2008-02.2: Undervoltage Load Shedding (UVLS): Misoperation to include UVLS equipment.

Guidelines and Technical Basis

Introduction

The standard drafting team provides the following discussion to support the approach to the standard. The information is meant to enhance the understanding of the reliability needs and deliverable expectations of each requirement, supported as necessary by technical principles and industry experience.

Guidelines for UVLS Program Definition

The definition for the term, “Undervoltage Load Shedding Program” or “UVLS Program” includes automatic load shedding programs that utilize only voltage inputs at locations where action is taken to shed load. As such, the failure of a single component is unlikely to affect the reliable operation of the program.

The UVLS Program definition excludes centrally controlled undervoltage-based load shedding, which utilizes inputs from multiple locations and may also utilize inputs other than voltages (such as generator reactive reserves, facility loadings, equipment statuses, etc.). The design and characteristics of a centrally controlled undervoltage-based load shedding system are the same as that of a Remedial Action Scheme (RAS), wherein load shedding is the remedial action. Therefore, just like for a RAS, the failure of a single component can compromise the reliable operation of centrally controlled undervoltage-based load shedding.

To ensure that the applicability of the standard includes only those undervoltage-based load shedding systems whose performance has an impact on system reliability, a UVLS Program must mitigate risk of one or more of the following: voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System (BES). An example of a program that would not fall under this category is undervoltage-based load shedding installed to mitigate damage to equipment or local loads that are directly affected by the low voltage event.

Figure 1 below is an example of a BES subsystem for which a UVLS system could be used as a solution to mitigate various issues following the loss of the 345 kV double circuit line between buses A and B. If the consequence of this Contingency does not impact the BES by leading to voltage instability, voltage collapse, or Cascading, a UVLS system (installed at either, or both, bus B and D) used to mitigate this Contingency would not fall under the definition of a UVLS Program. However, if this same UVLS system is used to mitigate an Adverse Reliability Impact outside this contained area, it would be classified as a wide-area undervoltage problem and would fall under the definition of UVLS Program.

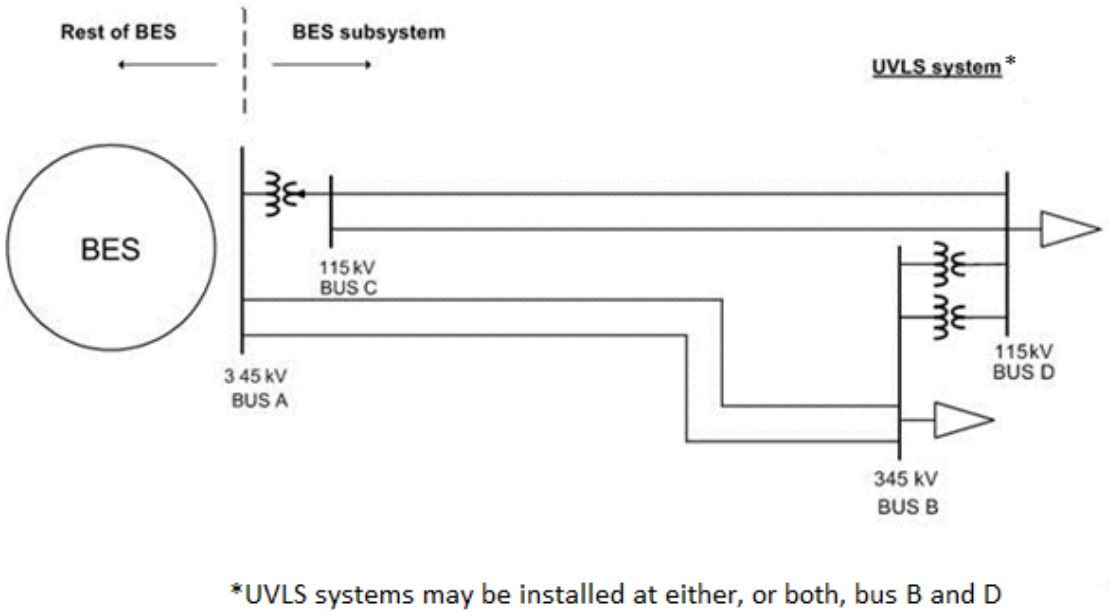


Figure 1: UVLS Subsystem

Guidelines for Requirements

Table 1 provides a high-level overview of the requirements contained in the standard.

Table 1: High-Level Requirement Overview

Requirement	Entity	Evaluate Program Effectiveness	Adhere to Program Specifications and Schedule	Perform Program Assessment (Periodic or Performance)	Develop a CAP to Address Program Deficiencies	Update and/or Share Program Data
R1	PC or TP	X				
R2	UVLS entity		X			
R3	PC or TP	X		X		
R4	PC or TP	X		X		
R5	PC or TP				X	
R6	PC					X
R7	UVLS entity					X
R8	PC					X

Guidelines for Requirement R1

A UVLS Program may be developed and implemented to either serve as a safety net system protection measure against unforeseen extreme Contingencies or to achieve specific system performance for known transmission Contingencies for which dropping of load is allowed under Transmission Planning (TPL) Reliability Standards. Regardless of the purpose, it is important that the UVLS Program being implemented is effective in terms that it mitigates undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Consideration should be given to voltage set points and time delays, rate of voltage decay or recovery, power flow levels, etc. when designing a UVLS Program.

For the UVLS Program to be effective in achieving its goal, it is also necessary that the UVLS Program is coordinated with generator voltage ride-through capabilities and other protection and control systems that may have an impact on the performance of the UVLS Program. Some of these protection and control systems may include, but are not limited to, transmission line protection, RAS, other undervoltage-based load shedding programs, autoreclosing, and controls of shunt capacitors, reactors, and static voltampere-reactive systems (SVSs).

For example, if the purpose of a UVLS Program is to mitigate fault-induced delayed voltage recovery (FIDVR) events in a large load center that also includes local generation, it is important that such a UVLS Program is coordinated with local generators' voltage ride-through capabilities. Generators in the vicinity of a load center are critical to providing dynamic voltage support to the system during FIDVR events. To maximize the benefit of on-line generation, the best practice may be to shed load prior to generation trip. However, occasionally, it may be best to let generation trip prior to load shed. Therefore, the impact of generation tripping should be considered while designing a UVLS Program.

Another example that can be highlighted is the coordination of a UVLS Program with automatic shunt reactor tripping devices if there are any on the system. Most likely, any shunt reactors on the system will trip off automatically after some time delay during low voltage conditions. In such cases, shunt reactors should be tripped before the load is shed to preserve the system. This may require coordination of time delays associated with the UVLS Program with shunt reactor tripping devices.

The examples given above demonstrate that, for a UVLS Program to be effective, proper consideration should be given to coordination of a UVLS Program with generator ride-through capabilities and other protection and control systems.

Guidelines for Requirement R2

Once a Planning Coordinator (PC) or Transmission Planner (TP) has identified a need for a UVLS Program, the Planning Coordinator or Transmission Planner will develop a program that includes specifications and an implementation schedule, which are then provided to UVLS entities per Requirement R1. Specifications may include voltage set points, time delays, amount of load to be shed, and the location at which load needs to be shed. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS

Program may not be effective and may not achieve its intended goal. The UVLS entity must document that all necessary actions were completed to implement the UVLS Program.

Similarly, when a Corrective Action Plan (CAP) to address UVLS Program deficiencies is developed by the Planning Coordinator or Transmission Planner and provided to UVLS entities per Requirement R5, UVLS entities must comply with the CAP and its associated implementation schedule to ensure that the UVLS Program is effective. The UVLS entity is required to complete the actions specified in the CAP, document the plan implementation, and retain the appropriate evidence to demonstrate implementation and completion.

Deferrals or other relevant changes to the UVLS Program specifications or CAP need to be documented so that the record includes not only what was planned, but what was implemented. Depending on the planning and documentation format used by the responsible entity, evidence of a successful execution could consist of signed-off work orders, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, paid invoices, photographs, walk-through reports, or other evidence.

For example, documentation of a CAP provides an auditable progress and completion confirmation for the identified UVLS Program deficiency:

CAP Example 1 - Corrective actions for a quick triggering problem; preemptive actions for similar installations:

The PC or TP obtains fault records from a UVLS entity that participates in its UVLS Program that indicate a group of UVLS relays triggered at the appropriate undervoltage level but with shorter delays than expected. The PC or TP directed the UVLS entity to schedule on-site inspections within three weeks. The results of the inspection confirmed that the delay-time programmed on the relays was 60 cycles instead of 90 cycles. The PC or TP then directed the UVLS entity to correct to a 90-cycle time delay setting of the UVLS relays identified to have shorter time delay settings within eight weeks.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to verify and adjust all remaining UVLS relays time delay settings within a one-year period.

The PC or TP verified completion of verification and adjustment of the time delay settings for all of the UVLS entity's equipment that participates in the PC or TP UVLS Program

CAP Example 2 - Corrective actions for a firmware problem; preemptive actions for similar installations:

The PC or TP obtains fault records on 6/4/2014 from a UVLS entity that participates in its UVLS Program. The UVLS entity also provided the fault records to the manufacturer, who responded on 6/11/2014 that the Misoperation[1] of the UVLS relay was caused by a

[1] Misoperation of Protection Systems reporting was initiated by the NERC Board of Trustees adopted NERC Rules of Procedure, Section 1600, Request for Data or Information. Refer to: *Request for Data of Information, Protection System Misoperation Data Collection*, August 14, 2014. http://www.nerc.com/pa/RAPA/ProctectionSystem Misoperations/PRC-004-3%20Section%201600%20Data%20Request_20140729.pdf.

bug in version 2 firmware, and recommended installing version 3 firmware. The PC or TP approved the UVLS entity's plan to schedule Version 3 firmware installation on 6/12/2014.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to install firmware version 3 at all of the UVLS entity's UVLS relays that are determined to be programmed with version 2 firmware. The completion date was scheduled no-later-than 12/31/2014.

The firmware replacements were completed on 12/4/2014.

Guidelines for Requirement R3

In addition to the initial studies required to develop a UVLS Program, periodic comprehensive assessments (detailed analyses) are required to ensure its continued effectiveness. This assessment is required to be completed at least once every 60 calendar months to capture the accumulated effects of minor changes to the system that have occurred since the last assessment was completed. However, at any point in time, a Planning Coordinator or Transmission Planner may also determine that a material change[2] to system topology or operating conditions affects the performance of the UVLS Program and therefore necessitates the same comprehensive assessment. Regardless of the trigger, each assessment should include an evaluation of each UVLS Program to ensure the continued integration through coordination.

This comprehensive assessment complements the TPL-001-4 annual assessment requirement to evaluate the impact of protection systems. The 60-month period is the same time frame used in TPL-001-4 and in PRC-006-1.

As specified in Requirement R3, a comprehensive assessment must be performed at least once every 60 calendar months. If a Planning Coordinator or Transmission Planner conducts a comprehensive assessment sooner for the reasons discussed above, the 60-month time period would restart upon completion of this assessment.

Guidelines for Requirement R4

After a voltage excursion event, the goal of the assessment required in Requirement R4 is to evaluate: (1) whether the UVLS Program resolved the undervoltage issues, and (2) the performance of the UVLS Program equipment. The assessment should include event data analysis, such as the relevant sequence of events leading to the undervoltage conditions (e.g., Contingencies, operation of protection systems, and RAS) and field measurements useful to analyzing the behavior of the system. A comprehensive description of the UVLS Program operation should be presented, including conditions of the trigger (e.g., voltage levels, time

[2] It is understood that the term material change is not transportable on a continent-wide basis. This determination must be made by the Planning Coordinator or Transmission Planner and should be accompanied by documentation to support the technical rationale for determining material changes.

delays) and amount of load shed for each affected substation. Assessment of the event is performed to evaluate the level of performance of the program for the event of interest and to identify deficiencies to be included in a CAP per Requirement R5. Misoperation of UVLS equipment is addressed as a deficiency. Reporting of UVLS equipment Misoperations are addressed by the NERC *Request for Data and Information, Protection System Misoperation Data Collection*.[3]

The studies and analyses showing the effectiveness of the UVLS Program can be similar to what is required in Requirements R1 and R3, but should include a clear link between the evaluation of effectiveness (in studies using simulations) and the analysis of the event (with measurements and event data) that actually occurred. For example, differences between the expected and actual system behavior for the event of interest should be discussed and modeling assumptions should be evaluated. Important discrepancies between the simulations and the actual event should be investigated.

Considering the importance of an event that involves the operation of a UVLS Program, the 12-calendar-month period provides adequate time to analyze the event and perform an assessment while identifying deficiencies within a reasonable time. This time period is also required in PRC-006-1.

Guidelines for Requirement R5:

Requirement R5 promotes the prudent correction of an identified problem during the assessment of a UVLS Program. Per Requirements R3 and R4, an assessment of an active UVLS Program is triggered:

- Within 12 calendar months of an event that resulted in a voltage excursion for which the program was designed to operate
- At least once every 60 calendar months. The default time frame of 60 calendar months or less between assessments has the intention to assure that the cumulative changes to the network and operating condition affecting the UVLS Program are evaluated

Since every UVLS is unique, if material changes are made to system topology or operating conditions, the Planning Coordinator or Transmission Planner will decide the degree to which the change in topology or operating condition becomes a material change sufficient to trigger an assessment of the existing UVLS Program.

A CAP is a list of actions and an associated timetable for implementation to remedy a specific problem. It is a proven tool for resolving operational problems. Per Requirement R5, the Planning Coordinator or Transmission Planner is required to develop a CAP and provide it to UVLS entities to accomplish the purpose of this requirement, which is to prevent future deficiencies in the UVLS Program, thereby minimizing risk to the system. Determining the cause

[3] Id.

of the deficiency is essential in developing an effective CAP to avoid future re-occurrence of the same problem. A CAP can be revised if additional causes are found.

Based on industry experience and operational coordination timeframes, three calendar months from the date an assessment is completed is a reasonable time frame for development of a CAP, including time to consider alternative solutions and coordination of resources. The "within three calendar months" time frame is solely to develop a CAP, including its implementation schedule, and provide it to UVLS entities. It does not include the time needed for its implementation by UVLS entities. This implementation time frame is dictated within the CAP's associated timetable for implementation, and the execution of the CAP according to its schedule is required in Requirement R2.

Guidelines for Requirements R6–R8

An accurate UVLS Program database is necessary for the Planning Coordinator or Transmission Planner to perform system reliability assessment studies and event analysis studies. Without accurate data, there is a possibility that annual reliability assessment studies that are performed by the Planning Coordinator or Transmission Planner can lead to erroneous results and therefore impact reliability. Also, without the accurate data, it is very difficult for the Planning Coordinator or Transmission Planner to duplicate a UVLS event and determine the root cause of the problem.

To support a UVLS Program database, it is necessary for each UVLS entity to provide accurate data to its Planning Coordinator. Each UVLS entity will provide the data according to the specified format and schedule provided by the Planning Coordinator. This is required in order for the Planning Coordinator to maintain and support a comprehensive UVLS Program database. By having a comprehensive database, the Planning Coordinator can embark on a reliability assessment or event analysis/benchmarking studies, identify the issues with the UVLS Program, and develop Corrective Action Plans.

The UVLS Program database may include, but is not limited to the following:

- Owner and operator of the UVLS Program
- Size and location of customer load, or percent of connected load, to be interrupted
- Corresponding voltage set points and clearing times
- Time delay from initiation to trip signal
- Breaker operating times
- Any other schemes that are part of or impact the UVLS Programs, such as related generation protection, islanding schemes, automatic load restoration schemes, underfrequency load shedding (UFLS), and RAS

Additionally, the UVLS Program database is required to be updated annually (once every calendar year) by the Planning Coordinator. The intent here is for UVLS entities to review the data annually and provide changes to the Planning Coordinators so that Planning Coordinators

can keep the databases current and accurate for performing event analysis and other assessments.

Finally, a Planning Coordinator is required to provide information to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of receipt of a written request. Thirty calendar days was selected as the time frame as it is considered to be reasonable and well-accepted by the industry. Also, this requirement of sharing the database with applicable functional entities supports the directive provided by FERC that requires an integrated and coordinated approach to UVLS programs (Paragraph 1509 of FERC Order No. 693).

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Applicability

This standard is applicable to Planning Coordinators and Transmission Planners that have or are developing a UVLS Program, and to Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator. These Distribution Providers and Transmission Owners are referred to as UVLS entities for the purpose of this standard.

The applicability includes both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs.

The phrase “Planning Coordinator or Transmission Planner” provides the latitude for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity.

Rationale for R1

In Paragraph 1509 from Order No. 693, FERC directed NERC to require an integrated and coordinated approach to all protection systems. The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability, and that each Planning Coordinator or Transmission Planner that develops a UVLS Program should evaluate the program’s viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage conditions that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. Though presented as separate items, the drafting team recognizes that the studies that show coordination considerations and that the program addresses undervoltage issues may be interrelated and presented as one comprehensive analysis.

In addition, Requirement R1 also requires the Planning Coordinator or Transmission Planner to provide the UVLS Program’s specifications and implementation schedule to applicable UVLS entities to implement the program. It is noted that studies to evaluate the effectiveness of the program should be completed prior to providing the specifications and schedule.

Rationale for R2

UVLS entities must implement a UVLS Program or address any necessary corrective actions for a UVLS Program according to the specifications and schedule provided by the Planning Coordinator or Transmission Planner. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal.

Rationale for R3

A periodic comprehensive assessment (detailed analysis) should be conducted to identify and catalogue the accumulated effects of minor changes to the system that have occurred since the last assessment was completed, and should include an evaluation of each UVLS Program to ensure the continued integration through coordination. This comprehensive assessment supplements the NERC Reliability Standard TPL-001-4 annual assessment requirement to evaluate the impact of protection systems.

Based on the drafting team's knowledge and experience, and in keeping with time frames contained in similar requirements from other PRC Reliability Standards, 60 calendar months was determined to be the maximum amount of time allowable between assessments. Assessments will be performed sooner than the end of the 60-calendar month period if the Planning Coordinator or Transmission Planner determines that there are material changes to system topology or operating conditions that affect the performance of a UVLS Program. Note that the 60-calendar-month time frame would reset after each assessment.

Rationale for R4

A UVLS Program not functioning as expected during a voltage excursion event for which the UVLS Program was designed to operate presents a critical risk to system reliability. Therefore, a timely assessment to evaluate (1) whether the UVLS Program resolved the undervoltage issues and (2) the performance of the UVLS Program equipment associated with the applicable event is essential. The 12 calendar months (from the date of the event) provides adequate time to coordinate with other Planning Coordinators, Transmission Planners, Transmission Operators, and UVLS entities, simulate pre- and post-event conditions, and complete the performance assessment.

Rationale for R5

If program deficiencies are identified during an assessment performed in either Requirement R3 or R4, the Planning Coordinator or Transmission Planner must develop a Corrective Action Plan (CAP) to address the deficiencies. Based on the drafting team's knowledge and experience with UVLS studies, three calendar months was determined to provide a judicious balance between the reliability need to address deficiencies expeditiously and the time needed to consider potential solutions, coordinate resources, develop a CAP and implementation schedule, and provide the CAP and schedule to UVLS entities.

It is noted that the three-month time frame is only to develop the CAP and provide it to UVLS entities and does not encompass the time UVLS entities have to implement the CAP. Requirement R2 requires UVLS entities to execute the CAP according to the schedule provided by the Planning Coordinator or Transmission Planner.

Rationale for R6

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R6 supports this reliability need by requiring the Planning Coordinator to update its UVLS Program database at least once each calendar year.

Rationale for R7

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R7 supports this reliability need by requiring the UVLS entity to provide UVLS Program data in accordance with specified parameters.

Rationale for R8

Requirement R8 supports the integrated and coordinated approach to UVLS programs directed by Paragraph 1509 of Order No. 693 by requiring that UVLS Program data be shared with neighboring Planning Coordinators and Transmission Planners within a reasonable time period. Requests for the database should also be fulfilled for those functional entities that have a reliability need for the data (such as the Transmission Operators that develop System Operating Limits and Reliability Coordinators that develop Interconnection Reliability Operating Limits).

Frequently Asked Questions

To succinctly address common comment themes that require drafting team response on Project 2008-02 UVLS (proposed PRC-010-1), the drafting team provides the following discussion in the construct of an FAQ format.

Introduction

This Frequently Asked Questions (FAQ) document was created during the development of PRC-010-1 (*Undervoltage Load Shedding*)[4,5] to succinctly address common comment themes with respect to the approach and intent of the Project 2008-02 Undervoltage Load Shedding (UVLS)[6] standard drafting team ("drafting team"). This FAQ document is the outcome of comments received during comment periods and multiple outreach sessions with industry. All comments submitted by industry during comment periods may be reviewed on the project page.

Subsequent to the adoption of PRC-010-1, the UVLS drafting team made minor revisions to the standard address the UVLS Misoperation identification and correction.[7] This FAQ document was amended to reflect up the approach and intent of the drafting team during the development of PRC-010-2 concerning Misoperation of UVLS equipment.

Purpose of Standard Revision

1) What is the basis for a revision of the existing UVLS standards?

The initial input into a revision of the existing UVLS standards is FERC Order No. 693,[8] Paragraph 1509, which directed the ERO to develop a modification of PRC-010-0 that "requires that an integrated and coordinated approach be included in all protection systems on the Bulk-Power System, including generators and transmission lines, generators' low voltage ride through capabilities, and UFLS and UVLS programs." In addition, *The Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*[9] ("August 14 Blackout Report") showed that proper coordination would have mitigated effects if UVLS was used as a tool.

Additional inputs included 1) recommendations from the NERC System Protection and Control Subcommittee (SPCS) in its December 2010 *Technical Review of UVLS-Related Standards*[10] to combine the four existing UVLS standards, revise the applicability to entities responsible for UVLS program design, implementation, and coordination, specifically include a requirement for

[4] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-010-1&title=Undervoltage%20Load%20Shedding.
[5] Adopted by the NERC Board of Trustees on November 14, 2014.
[6] http://www.nerc.com/pa/Stand/Pages/Project-2008-02-Undervoltage-Load-Shedding.aspx
[7] Refer to Project 2010-05.1, which developed PRC-004-3 (Protection System Misoperation Identification and Correction) concurrently with the development of PRC-010-1. (http://www.nerc.com/pa/Stand/Pages/Project2010-05_Protection_System_Misoperations.aspx).
[8] http://www.nerc.com/docs/docs/ferc/order_693.pdf.
[9] http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf.
[10] http://www.nerc.com/docs/pc/spctf/PRC-010_022%20Report_Approved_20101208.pdf.

assessment of coordination between UVLS programs and all other protection systems, and differentiate post-event validation of UVLS program design from verifying correct operation of UVLS equipment; 2) the existing UVLS standards were not in the current results-based format; 3) the preceding revision of the underfrequency load shedding (UFLS) standards had similar types of requirements and had been completed under the construct of a consolidation; and 4) the Independent Expert Review Panel recommendations, which included an evaluation of the existing standards' applicability and level of specificity.

The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability. As part of the revision to address this, the drafting team also agreed that an evaluation and consolidation of the existing UVLS standards was necessary to meet current Reliability Standard development initiatives and to provide clear, comprehensive requirements to address the application and coordination of UVLS.

2) UVLS programs are not mandatory—is compliance for an optional tool necessary?

The drafting team asserts that a key takeaway from the August 14 Blackout Report is that coordination of UVLS with other protection systems could have mitigated the effects if UVLS was used as a tool. Although the use of UVLS is not mandatory, if it is determined that this system preservation measure is necessary to support reliability and a UVLS program is installed, the program needs to be properly coordinated, implemented, and assessed due to the inherent associated reliability risks. As such, there needs to be a level of performance required to properly protect system reliability. Of note, PRC-010-1 and PRC-010-2 apply to the defined term "UVLS Program," which limits the standard's applicability to only those undervoltage-based load shedding programs whose performance has an impact on system reliability.[11]

Coordination with Project 2009-03 Emergency Operations

3) EOP-003-2 has potential redundant requirements with proposed PRC-010-1—how is this being addressed?

As part of its five-year review, Project 2009-03 – Emergency Operations (EOP) identified EOP-003-2 (*Load Shedding Plans*),[12] Requirements R2, R4, and R7 as being more properly covered by Project 2008-02 – UVLS. Both projects were strategically coordinated to move in lockstep from a timing perspective to address these requirements. Project 2009-03 – EOP proposed to revise and consolidate EOP-001-2.1b (*Emergency Operations Planning*),[13] EOP-002-3 (Capacity and Energy Emergencies),[14] and EOP-003-2 to create EOP-011-1, will retire the noted EOP-003-2

[11] The term "UVLS Program" used herein was adopted by the NERC Board of Trustees on November 14, 2014.
[12] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-003-2&title=Load%20Shedding%20Plans.
[13] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-001-2.1b&title=Emergency%20Operations%20Planning.
[14] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-002-3&title=Capacity%20and%20Energy%20Emergencies.

requirements (among other revisions), and the Project 2008-02 – UVLS *Mapping Document* will show how PRC-010-1 encompasses the retired content accordingly. Slated to have aligning effective dates, both EOP-011-1 (*Emergency Operations*)[15] and PRC-010-1 will be posted and balloted separately but concurrently, so that industry stakeholders will be able to clearly evaluate the transition. Please see the posted Project 2008-02 UVLS Project Coordination Plan for more information.

"UVLS Program" Definition

4) Why is the introduction of the new defined term "UVLS Program" necessary?

The drafting team found it necessary to introduce the term "UVLS Program" for inclusion in the *Glossary of Terms Used in NERC Reliability Standards*[16] ("NERC Glossary") because different types of UVLS systems need to be treated appropriately with respect to reliability requirements. Therefore, the term establishes which UVLS systems PRC-010-1 will apply to an: "automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included."

The definition is meant to inherently exclude locally-applied relays that are designed to protect a contained area or, in other words, are not designed to mitigate wide-area voltage collapse. This exclusion is not explicit in these terms in the enforceable language of the definition since the meaning and measurement of "local" or "wide-area" varies greatly on a continent-wide basis and could potentially be interpreted differently by auditors and the applicable functional entities. Therefore, the definition as written is meant to provide flexibility for the Planning Coordinator or Transmission Planner to determine if a UVLS system falls under the defined term with respect to its impact on the reliability of the BES (voltage instability, voltage collapse, or Cascading). To further support the intended exclusion, further discussion and an example are provided on in the PRC-010-1 and PRC-010-2 Guidelines and Technical Basis section under the heading "Guidelines for UVLS Program Definition."

The definition does explicitly note that the term excludes centrally controlled undervoltage-based load shedding. This type of load shedding is excluded because the drafting team asserts that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with those of a Special Protection System (SPS) or Remedial Action Scheme (RAS) and should therefore be subject to SPS or RAS-related Reliability Standards. See PRC-010-1 and PRC-010-2 Guidelines and Technical Basis section under the heading "Guidelines for UVLS Program Definition" for further discussion.

[15] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-011-1&title=Emergency%20Operations.
[16] http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

5) If the definition excludes certain types of UVLS, does this preclude an "integrated" approach (FERC Order No. 693, Paragraph 1509)?

The defined term "UVLS Program" clarifies which UVLS systems are subject to the requirements in PRC-010-1 and PRC-010-2. The resulting exclusions from these versions of the standard do not preclude an "integrated" approach because the standard requires that an entity coordinate with all other protection and control systems as necessary, which may include other types of UVLS (i.e., locally-applied UVLS relays and centrally controlled undervoltage-based load shedding).

6) Where will centrally controlled undervoltage-based load shedding be covered?

As explained immediately above, the Requirements of PRC-010-1 and PRC-010-2 are applicable to the proposed NERC Glossary term "UVLS Program," which excludes centrally controlled undervoltage-based load shedding because its design and characteristics are commensurate with those of an SPS or RAS. However, the NERC Glossary during the development of PRC-010-1 definition of "Special Protection System" excluded UVLS. Therefore, the work under Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems) combined the NERC Glossary definition of "Special Protection System" into the single term "Remedial Action Scheme."[17] The definition revisions specifically excluded UVLS Programs, therefore including centrally controlled undervoltage-based shedding.

Consequently, the introduction of the term "UVLS Program" and the conforming revision to the term "Remedial Action Scheme" explicitly clarifies that RAS-related standards are applicable to centrally controlled undervoltage-based load shedding. The implementation plan for the revised definition of "Remedial Action Scheme" will address entities that will have newly identified RAS resulting from the application of the defined term.

Similar to the coordination effort with Project 2009-03 – EOP explained above, Project 2008-02 – UVLS and Project 2010-05.2 – SPS were coordinated to ensure that the effective dates of the adopted definitions of "Remedial Action Scheme" and "UVLS Program," the PRC-010-1 and PRC-010-1 Reliability Standards, and all associated retirements align.

7) Is the term "UVLS Program" inclusive of a collection of independent UVLS relays?

No; multiple independent relays do not constitute a program. While the definition stipulates that a UVLS Program consists of distributed relays and controls, the definition specifies that it must be "[a]n automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System(BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included."

[17] Adopted by the NERC Board of Trustees on November 14, 2014.

Applicability

8) What is meant by the phrase "Planning Coordinator or Transmission Planner"?

The PRC-010-1 and PRC-010-2 Reliability Standards are applicable to both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs. The phrase "Planning Coordinator or Transmission Planner" provides the flexibility for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity. In addition, the requirements containing this phrase have specific language to qualify the responsible entity. For example, Requirement R1 states: "Each Planning Coordinator or Transmission Planner *that is developing* a UVLS Program shall . . ." This language provides clarity that the applicable entity would be the one that is developing the program.

9) Why is the Transmission Operator not included?

While the Transmission Operator may be involved with UVLS Program activities, the drafting team did not identify any required performance for the Transmission Operator that was necessary to capture within PRC-010-1 and PRC-010-2, since the Transmission Operator does not have the resources necessary to implement program specifications. If responsibilities are delegated to the Transmission Operator by the Transmission Owner, the Transmission Owner is still the accountable party.

To the extent that the Transmission Operator is required to have knowledge of system relays and protection systems, the drafting team notes that this requirement is covered under PRC-001-1.1 (*System Protection Coordination*),[18] Requirement R1. It is also noted that manual load shedding, for which the Transmission Operator is responsible, is not in the purview of PRC-010-1 and PRC-010-2, as it is covered under current EOP-003-2 and will subsequently be covered by proposed EOP-011-1 (see Project 2009-03 – Emergency Operations).

10) What about UVLS schemes owned by Transmission Owners, Distribution Providers, or Transmission Operators that are not required by the planner?

The PRC-010-1 and PRC-010-2 Reliability Standards are applicable to the term "UVLS Program." The drafting team notes that, by its defining attributes, a UVLS Program would be required and developed by a Planning Coordinator or Transmission Planner. The nature of a UVLS scheme developed or required by a Distribution Provider, Transmission Operator, or Transmission Owner would not meet the attributes of the defined term and would therefore not have the design and characteristics necessary to be subject to the requirements of PRC-010-1 and PRC-010-2.

[18] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-001-1.1&title=System%20Protection%20Coordination.

Requirements R1, R3, R4, and R5

11) What is required to evaluate the coordination referenced in Requirement R1, part 1.2?

Requirement R1 requires each Planning Coordinator or Transmission Planner that develops a UVLS Program to evaluate the program's viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage issues that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. As such, the requirement is meant to provide flexibility for an entity to make the proper determinations, including the considerations for coordination, with respect to program effectiveness based on system characteristics. For further guidance on and examples of coordination considerations, please see the portion of the Guidelines and Technical Basis section under the Requirement R1 heading.

12) Requirements R1, R3, and R4 seem to all require evaluations of program effectiveness—how are they different?

Requirements R1, R3, and R4 do require evaluations of program effectiveness, but they are each at distinct points in time.

Requirement R1 requires evaluation of program effectiveness (by way of the qualifying parts) at the onset of program development, or during the initial planning stage, prior to implementation. Requirement R3 requires the same objectives of an evaluation of effectiveness, but at the point of a mandatory periodic review (at least once every 60 calendar months). Requirement R4 addresses the performance of a UVLS Program after an event (for applicable voltage excursion) to evaluate whether the UVLS Program resolved the undervoltage issues associated with the event.

It is noted that, because of the separate activities of each requirement, UVLS Program deficiencies found as a result of the assessments performed in Requirement R3 or R4 would not be violations of Requirement R1.

13) Requirement R4 would require the Planning Coordinator or Transmission Planner to review all voltage excursions—isn't this unduly burdensome?

While Requirement R4 essentially requires the Planning Coordinator or Transmission Planner to review all voltage excursions to see if they fall below the initializing set points of the UVLS Program, the drafting team contends that it will be clearly evident if voltage falls below the UVLS threshold because either a) UVLS devices will operate; or b) the system will experience the adverse conditions the UVLS Program was installed to mitigate.

In addition, the drafting team acknowledges that the Planning Coordinator or Transmission Planner may not have the ability to know when voltage excursions are occurring since they are not operating entities. However, a process for the Transmission Operator, Transmission Owner,

or Distribution Provider to notify the Transmission Planner or Planning Coordinator of such voltage excursion events is consistent with standard utility practice.

14) PRC-022-1 required the analysis of UVLS Misoperations. How is this addressed in PRC-010-1?

One of the recommendations in the SPCS report was to clearly differentiate between the post-event process of validating the effectiveness of the UVLS program design, its coordination with other protection and control systems, and the potential need to modify the program design (activities addressed in PRC-010-1) and the process of verifying correct operation of UVLS equipment. Because PRC-010-1 was not specific concerning the Misoperation of UVLS equipment, the drafting team made a subsequent revision creating PRC-010-2. Version two (PRC-010-2) now requires that the assessment according to Requirement R4 include the performance (i.e., operation or non-operation) of the UVLS Program equipment.

Relative to the assessment, Requirement R5 requires that a Corrective Action Plan be developed to address any identified deficiencies. This structure ensures that UVLS Program equipment is assessed to identify any Misoperation which could affect BES reliability. Although, the UVLS drafting team maintained during development of PRC-010-1 that verifying correct operation of UVLS equipment should be addressed in PRC-004, the drafting team included UVLS that is intended to trip one or more BES Elements in the proposed PRC-004-5.

Requirements R6, R7, and R8

15) Do Requirements R6, R7, and R8 overlap with the requirements of MOD-032-1?

While both MOD-032-1 (*Data for Power System Modeling and Analysis*)[19] and Requirements R6, R7, and R8 of PRC-010-1 and PRC-010-2 address data requirements, MOD-032-1 establishes overarching modeling data requirements with respect to consistency in format and reporting procedures, whereas the PRC-010-1 and PRC-010-2 requirements address the need to maintain and share data and databases for the purposes of studies for use in event analyses for UVLS Programs specifically. While Reliability Standards in general may have overlap in this manner, the activities in these requirements remain distinctly different.

[19] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=MOD-032-1&title=Data%20for%20Power%20System%20Modeling%20and%20Analysis.

16) Requirements R6, R7, and R8 appear to be administrative — doesn't this conflict with Paragraph 81 criteria?[20]

Proper maintenance and timely sharing of UVLS Program data as required by Requirements R6, R7, and R8 is necessary to inform the Planning Coordinator or Transmission Planner's studies and analyses. While administrative tasks are required, the tasks have a core reliability-based need.

In addition, Requirements R6, R7, and R8 were written to emulate FERC-approved PRC-006-2 (*Automatic Underfrequency Load Shedding*)[21,22] data requirements. While some of these analogous requirements in PRC-006-2 are listed as candidates for Phase 2 of the Paragraph 81 project, they are not yet approved as meeting the criteria; furthermore, the Independent Expert Review Panel has recommended that these Paragraph 81 candidates not be included for deletion, citing that "there should be a clear expectation for Planning Coordinators to share data necessary to determine their UFLS program parameters."

[20] Refer to Standards Independent Expert Review Project (IERP). http://www.nerc.com/pa/Stand/Standard%20Development%20Plan/Standards_Independent_Experts_Review_Project_Report-SOTC_and_Board.pdf.
[21] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-006-2&title=Automatic%20Underfrequency%20Load%20Shedding.
[22] Adopted by the NERC Board of Trustees on November 14, 2014.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The NERC Board of Trustees adopted PRC-010-1 on November 13, 2014.
2. The NERC Standards Committee authorized the initial posting on February 18, 2015.

Description of Current Draft

The UVLSSDT is posting Draft 1 of PRC-010-2 – Undervoltage Load Shedding for a 45-day initial formal comment period and concurrent/parallel initial ballot in the last ten days of the comment period. The draft contains revisions to Requirements R4 and R5 to address UVLS equipment.

Anticipated Actions	Date
45-day formal comment period with ballot	February 2015
10-day final ballot	April 2015
Board adoption	May 2015

Project Development Background

The undervoltage load shedding (UVLS) standard drafting team (SDT) was tasked with addressing Misoperation of UVLS equipment during the development of version one of PRC-010 and version three of PRC-004 in Project 2010-05.1 (i.e., Misoperation). This project has been named phase 2 of Project 2008-02 (i.e., UVLS) for clarity purposes. Each SDT for these two projects outlined work necessary to address Misoperation of UVLS equipment. This work was deferred, at the time, because both PRC-010-1 and PRC-004-3 contained dependencies with other projects requiring their completion. This phase two is a continuation of the work performed under the Standards Authorization Request (SAR) for Project 2008-02.

The revisions proposed in Reliability Standard PRC-010-2 meet the following objectives:

- Address the UVLS Misoperation the remaining work due to the retirement of PRC-022-1 (Undervoltage Load Shedding Program Performance) during the development of PRC-010-1 (Undervoltage Load Shedding)
- Ensure UVLS equipment (i.e., operation or non-operation) within the UVLS Program is assessed and mitigated

Basis for Revision

Originally, Misoperation of UVLS equipment was planned to be appended to a future version of PRC-004 (Protection System Misoperation Identification and Correction). The SDT is proposing a two-prong approach by revising both PRC-004 and PRC-010 to address the concern of identifying Misoperations of UVLS equipment in PRC-022-1.

First, the SDT proposes an addition to the Applicability section of PRC-004 to include UVLS that is intended to trip one or more Bulk Electric System (BES) Elements. This is consistent with previous communication to industry about addressing Misoperation of UVLS equipment. Entities will be required to address UVLS that trips a BES Element similarly to other Protection Systems in PRC-004. While the revision to PRC-004 consistent with the communicated approach, the SDT determined that the proposed revision fails to address the performance (operation or non-operations) of UVLS Program equipment not covered by the strict processes of PRC-004.

Second, the SDT is proposing clarifying revisions in PRC-010-2, Requirements R4 and R5 to address UVLS Program equipment performance. These revisions are not requiring UVLS entities to address UVLS protective relays not covered by the strict processes of PRC-004; however, PRC-010-2 is requiring UVLS entities to address the deficiencies (e.g., Misoperations) identified in the assessment performed by Planning Coordinator or Transmission Planner in Requirement R4. Deficiencies include the performance (operation or non-operation) issues of UVLS Program equipment. These deficiencies, if any, are addressed by the UVLS entities through a Corrective Action Plan (CAP) developed in Requirement R5 and executed by the UVLS entities in Requirement R2 of PRC-010.

The term “Misoperation” as defined by the Glossary of Terms Used in NERC Reliability Standards is not used within the Requirements of PRC-010; however, the term is used in the Guidelines and Technical Basis section of the standard to provide clarity that UVLS Program equipment deficiencies include Misoperations that are to be corrected by UVLS entities. The PRC-010-2 Reliability Standard mandates that UVLS entities are to correct the deficiencies identified by the Planning Coordinator or Transmission Planner, such as Misoperation of UVLS equipment. Deficiencies are identified through either the periodic assessment or an assessment performed following an event and included in a CAP to the UVLS entity. The structure used by the SDT allows the Planning Coordinator and Transmission Planner to assess UVLS equipment for Misoperation under PRC-010 rather than the Generator Owner, Transmission Owner, and Distribution Provider applicable to the strict processes of PRC-004.

The two-pronged approach ensures that any UVLS Program equipment containing a deficiency is identified and corrected under PRC-010 and UVLS that trips a BES Element under is corrected under PRC-004 to address the requirements in the retired PRC-022-1.

When this standard receives Board adoption, the rationale boxes in the Supplemental Material section of the standard will remain. The rationale box for Requirement R5 will be removed.

A. Introduction

1. **Title:** Undervoltage Load Shedding

2. **Number:** PRC-010-~~1~~-2

3. **Purpose:** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Coordinator.

   4.1.2 Transmission Planner.

   4.1.3 Undervoltage load shedding (UVLS) entities – Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator.

5. **Effective Date:** See Project 2008-02.2 Implementation Plan.

~~1. Background:~~

~~PRC-010-1 – Undervoltage Load Shedding is a consolidation and revision of the following Reliability Standards:~~

- ~~PRC-010-0 – Assessment of the Design and Effectiveness of UVLS Program~~
- ~~PRC-020-1 – Under-Voltage Load Shedding Program Database~~
- ~~PRC-021-1 – Under-Voltage Load Shedding Program Data~~
- ~~PRC-022-1 – Under-Voltage Load Shedding Program Performance~~

~~The UVLS Standard Drafting Team (or drafting team) developed the revised PRC-010-1 to meet the following objectives:~~

- ~~Address the FERC directive in Order No. 693, Paragraph 1509 to modify PRC-010-0 to require an integrated and coordinated approach to all protection systems.~~
- ~~Replace the applicability to and involvement of the Regional Reliability Organization (RRO) in PRC-020-1 and PRC-021-1.~~
- ~~Consolidate the UVLS-related standards into one comprehensive standard (similar to the construct of FERC-approved PRC-006-1 – Automatic~~

~~Underfrequency Load Shedding).~~

- ~~Clearly identify and separate centrally controlled undervoltage□based load shedding due to the reliability requirements needed for this type of load shedding as compared to other UVLS systems.~~
- ~~Create a single results□based standard that addresses current reliability issues associated with UVLS.~~

B. Requirements and Measures

R1. Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS Program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design.

1.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M1. Acceptable evidence may include, but is not limited to, date-stamped studies and analyses, reports, or other documentation detailing the effectiveness of the UVLS Program, and date-stamped communications showing that the UVLS Program specifications and implementation schedule were provided to UVLS entities.

R2. Each UVLS entity shall adhere to the UVLS Program specifications and implementation schedule determined by its Planning Coordinator or Transmission Planner associated with UVLS Program development per Requirement R1 or with any Corrective Action Plans per Requirement R5. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Acceptable evidence must include date-stamped documentation on the completion of actions and may include, but is not limited to, identifying the equipment armed with UVLS relays, the UVLS relay settings, associated Load summaries, work management program records, work orders, and maintenance records.

R3. Each Planning Coordinator or Transmission Planner shall perform a comprehensive assessment to evaluate the effectiveness of each of its UVLS Programs at least once every 60 calendar months. Each assessment shall include, but is not limited to, studies and analyses that evaluate whether: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. The UVLS Program resolves the identified undervoltage issues for which the UVLS Program is designed.

3.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including,

but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M3. Acceptable evidence may include, but is not limited to, date-stamped reports or other documentation detailing the assessment of the UVLS Program.

Rationale for Requirement R4: Refer to the Supplemental Section at the end of the document for the rationale.

R4. Each Planning Coordinator or Transmission Planner shall, within 12 calendar months of an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, perform an assessment to evaluate ~~whether its UVLS Program resolved the undervoltage issues associated with the event.~~: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Whether its UVLS Program resolved the undervoltage issues associated with the event, and

4.2. The performance (i.e., operation and non-operation) of the UVLS Program equipment.

M4. Acceptable evidence may include, but is not limited to, date-stamped event data, event analysis reports, or other documentation detailing the assessment of the UVLS Program and associated equipment.

R5. Each Planning Coordinator or Transmission Planner that identifies deficiencies ~~in its UVLS Program~~ during an assessment performed in either Requirement R3 or R4 shall develop a Corrective Action Plan to address the deficiencies and subsequently provide the Corrective Action Plan, including an implementation schedule, to UVLS entities within three calendar months of completing the assessment. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Acceptable evidence must include a date-stamped Corrective Action Plan that addresses identified deficiencies and may also include date-stamped reports or other documentation supporting the Corrective Action Plan. Evidence should also include date-stamped communications showing that the Corrective Action Plan and an associated implementation schedule were provided to UVLS entities.

R6. Each Planning Coordinator that has a UVLS Program in its area shall update a database containing data necessary to model the UVLS Program(s) in its area for use in event analyses and assessments of the UVLS Program at least once each calendar year. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. Acceptable evidence may include, but is not limited to, date-stamped spreadsheets, database reports, or other documentation demonstrating a UVLS Program database was updated.

R7. Each UVLS entity shall provide data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of a UVLS Program database. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M7. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating data was provided to the Planning Coordinator as specified.

R8. Each Planning Coordinator that has a UVLS Program in its area shall provide its UVLS Program database to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of a written request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M8. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating that the UVLS Program database was provided within 30 calendar days of receipt of a written request.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Planning Coordinator, Transmission Planner, Distribution Provider, and Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The applicable entity shall retain documentation as evidence for six calendar years.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

"Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	High	N/A	N/A	N/A	The applicable entity that developed the UVLS Program failed to evaluate the program's effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to UVLS entities in accordance with Requirement R1, including the items specified in Parts 1.1 and 1.2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Long-term Planning	High	N/A	N/A	The applicable entity failed to adhere to the UVLS Program specifications in accordance with Requirement R2. OR The applicable entity failed to adhere to the implementation schedule in accordance with Requirement R2.	The applicable entity failed to adhere to the UVLS Program specifications and implementation schedule in accordance with Requirement R2.
R3	Long-term Planning	Medium	N/A	N/A	N/A	The applicable entity failed to perform an assessment at least once during the 60 calendar months in accordance with Requirement R3, including the items specified in Parts 3.1 and 3.2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Medium	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 12 calendar months but less than or equal to 13 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 13 calendar months but less than or equal to 14 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 14 calendar months but less than or equal to 15 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 15 calendar months after an applicable event. OR The applicable entity failed to perform an assessment in accordance with Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning	Medium	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by less than or equal to 15 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 15 calendar days but less than or equal to 30 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 30 calendar days but less than or equal to 45 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 45 calendar days. OR The responsible entity failed to develop a Corrective Action Plan or provide it to UVLS entities in accordance with Requirement R5.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	Operations Planning	Lower	The applicable entity updated the database in accordance with Requirement R6 but was late by less than or equal to 30 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 60 calendar days but less than or equal to 90 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 90 calendar days. OR The applicable entity failed to update the database in accordance with Requirement R6.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	Operations Planning	Lower	The applicable entity provided data in accordance with Requirement R7 but was late by less than or equal to 30 calendar days per the specified schedule. OR The applicable entity provided data in accordance with Requirement R7 but the data was not provided according to the specified format.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 30 calendar days but less than or equal to 60 calendar days per the specified schedule.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 60 calendar days but less than or equal to 90 calendar days per the specified schedule.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 90 calendar days per the specified schedule. OR The applicable entity failed to provide data in accordance with Requirement R7.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	Operations Planning	Lower	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by less than or equal to 15 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 15 calendar days but less than or equal to 30 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 30 calendar days but less than or equal to 45 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 45 calendar days. OR The applicable entity failed to provide its UVLS Program database in accordance with Requirement R8.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	
0	April 1, 2005	Effective Date	
0	February 7, 2013	Adopted by NERC Board of Trustees	R2 and associated elements for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.
1	November 13, 2014	Adopted by NERC Board of Trustees	Revisions made under Project 2008-02: Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS) to address directive issued in FERC Order No. 763.
2		Adopted by NERC Board of Trustees	Revisions made under Project 2008-02.2: Undervoltage Load Shedding (UVLS): Misoperation to include UVLS equipment.

Guidelines and Technical Basis

Introduction

~~PRC-010-1 is a single, comprehensive standard that addresses the same reliability principles outlined in its legacy standards, PRC-010-0, PRC-020-1, PRC-021-1, and PRC-022-1. The standard also addresses a FERC directive from Order No. 693, Paragraph 1509. This paragraph directs NERC to develop a modification to PRC-010-0 that requires an integrated and coordinated approach to all protection systems, including generators and transmission lines, generators' low voltage ride-through capabilities, and underfrequency load shedding (UFLS) and UVLS programs.~~

~~Since FERC-approved PRC-006-1 – Automatic Underfrequency Load Shedding was developed under a similar construct of combining existing standards and addressing a FERC Order No. 693 directive, the drafting team looked to this standard as a guide. With the understanding that UVLS and UFLS systems have fundamental differences, the drafting team adopted PRC-006-1's industry-vetted reliability principles and language as applicable to UVLS Programs.~~

~~The drafting team's established purpose for PRC-010-1 is to clearly define the responsibilities of applicable entities to pursue an integrated and coordinated approach to the design, evaluation, and reliable operation of UVLS Programs. Since the need for and design of UVLS Programs is unique to each system preservation footprint, the intent of the standard is to provide a framework of reliability requirements for such programs to which each individual entity can apply its program's specific considerations and characteristics. The drafting team emphasizes that PRC-010-1 does not require a mandatory UVLS Program, nor does this standard address the need to have a UVLS Program. PRC-010-1 applies only after an entity has determined the need for a UVLS Program as a result of its own planning studies.~~

~~The~~The standard drafting team provides the following discussion to support the approach to the standard. The information is meant to enhance the understanding of the reliability needs and deliverable expectations of each requirement, supported as necessary by technical principles and industry experience.

~~The design and characteristics of a centrally controlled undervoltage-based load shedding system are commensurate with a Special Protection System (SPS) or Remedial Action Scheme (RAS), therefore, the drafting team maintains that this type of load shedding should be covered by SPS or RAS-related Reliability Standards. Therefore, PRC-010-1 introduces a new Glossary of Terms Used in NERC Reliability Standards term, UVLS Program, to establish the applicability of PRC-010-1 to automatic load shedding programs consisting of distributed relays and controls used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Undervoltage-based load shedding that does not have such an impact as determined by the Planning Coordinator or Transmission Planner is not included. It is further noted that this term excludes centrally controlled undervoltage-based load shedding.~~

~~Subsequently, since the current Glossary of Terms Used in NERC Reliability Standards definition of Special Protection System excludes UVLS, concurrent Project 2010□05.2 – Special Protection Systems (Phase 2 of Protection Systems) will adjust the definition to exclude only UVLS Programs as defined above and therefore include centrally controlled undervoltage□based load shedding. Of note, the drafting team for Project 2010□05.2 is proposing to change the term from Special Protection System to Remedial Action Scheme. Accordingly, PRC□010□1 uses the term Remedial Action Scheme instead of Special Protection System. In the current inventory of NERC Reliability Standards, there is one instance of the term undervoltage load shedding program, which is in NUC□001□2.1. Project 2012□13 Nuclear Plant Interface Coordination has adjusted the language of this reference in proposed NUC□001□3 to eliminate any potential confusion of a lowercase usage of a defined term. Likewise, future projects containing standards that feature variations of the term (e.g., undervoltage load shedding system) will also be advised to consider the newly defined term.~~

~~Requirements of the revised Reliability Standard PRC□010□1 meet the following objectives:~~

- ~~Evaluate a UVLS Program's effectiveness prior to implementation, including the program's coordination with other protection systems and generator voltage ride-through capabilities.~~
- ~~Adhere to UVLS Program specifications and implementation schedule.~~
- ~~Perform periodic assessment and performance analysis of UVLS Programs and resolve identified deficiencies.~~
- ~~Maintain and share UVLS Program data.~~

~~Also of note, Project 2009□03 – Emergency Operations is proposing EOP□011□1, which, as part of the overall revisions, retires specific requirements from EOP□003□2 – Load Shedding Plans to eliminate identified redundancy between PRC□010□1 and EOP□003□2. In addition, the UVLS drafting team's intention is for PRC□004 to address Misoperations of UVLS Programs that are intended to trip one or more BES Elements. A change to make these types of UVLS Programs explicitly applicable to PRC□004 will be addressed once PRC□004□3 – Protection System Misoperation Identification and Correction is completed under Project 2010□05.1 – Misoperations (Phase 1 of Protection Systems).~~

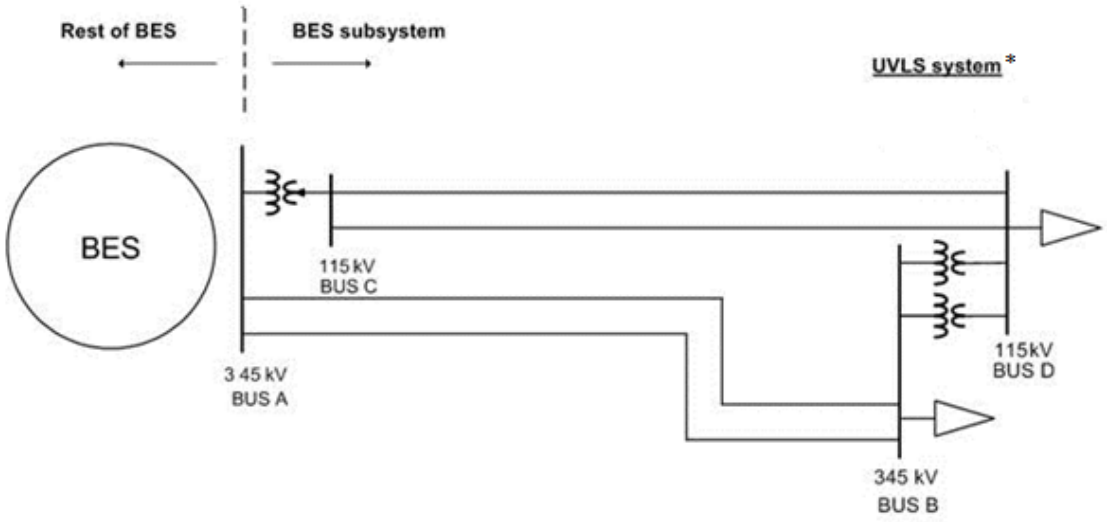
Guidelines for UVLS Program Definition

The definition for the term~~-~~, “Undervoltage Load Shedding Program” or “UVLS Program” includes automatic load shedding programs that utilize only voltage inputs at locations where action is taken to shed load. As such, the failure of a single component is unlikely to affect the reliable operation of the program.

The ~~definition for the term~~ UVLS Program definition excludes centrally controlled undervoltage-based load shedding, which utilizes inputs from multiple locations and may also utilize inputs other than voltages (such as generator reactive reserves, facility loadings, equipment statuses, etc.). The design and characteristics of a centrally controlled undervoltage-based load shedding system are the same as that of a Remedial Action Scheme (RAS~~,~~), wherein load shedding is the remedial action. Therefore, just like for a RAS, the failure of a single component can compromise the reliable operation of centrally controlled undervoltage-based load shedding.

To ensure that the applicability of the standard ~~is to~~includes only those undervoltage-based load shedding systems whose performance has an impact on system reliability, a UVLS Program must mitigate risk of one or more of the following: voltage instability, voltage collapse, or Cascading impacting the ~~BES.~~Bulk Electric System (BES). An example of a program that would not fall under this category is undervoltage-based load shedding installed to mitigate damage to equipment or local loads that are directly affected by the low voltage event.

~~Below~~Figure 1 below is an example of a BES subsystem for which a UVLS system could be used as a solution to mitigate various issues following the loss of the 345 kV double circuit line between ~~bus~~buses A and ~~bus~~ B. If the consequence of this Contingency does not impact the BES by leading to voltage instability, voltage collapse, or Cascading ~~involving the BES.~~, a UVLS system (installed at either, or both, bus B and D) used to mitigate this ~~case~~Contingency would not fall under the definition of a UVLS Program. However, if this same UVLS system ~~would be~~is used to mitigate an Adverse Reliability Impact outside this contained area, it would be classified as a wide-area undervoltage problem and would fall under the definition of UVLS Program.



*UVLS systems may be installed at either, or both, bus B and D

~~High Level Requirement Overview~~

~~Requirement~~

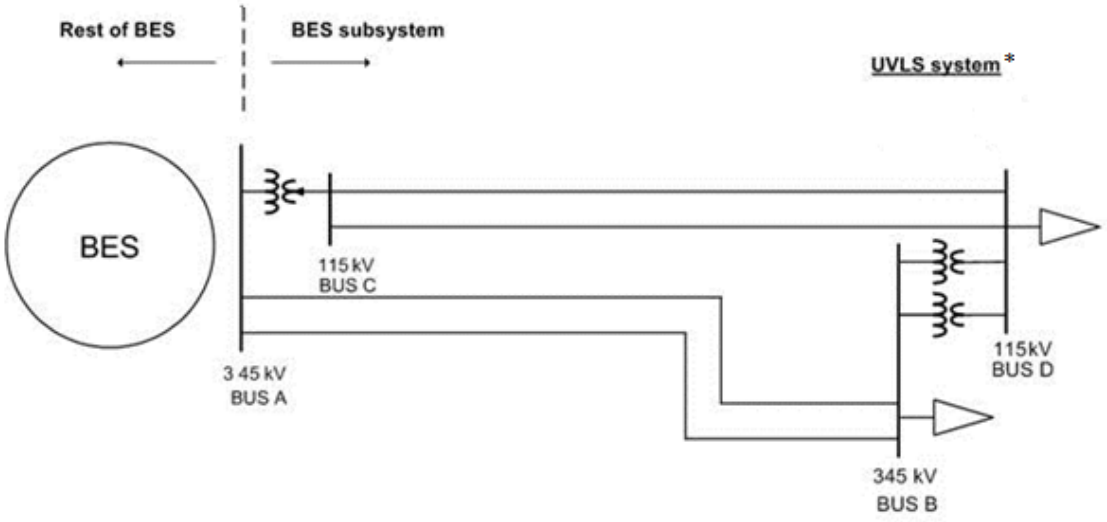


Figure 1: UVLS Subsystem

Guidelines for Requirements

Table 1 provides a high-level overview of the requirements contained in the standard.

Table 1: High-Level Requirement Overview

Requirement	Entity	Evaluate Program Effectiveness	Adhere to Program Specifications and Schedule	Perform Program Assessment (Periodic or Performance)	Develop a CAP to Address Program Deficiencies	Update and/or Share Program Data
R1	PC or TP	X				
R2	UVLS entity		X			
R3	PC or TP	X		X		
R4	PC or TP	X		X		
R5	PC or TP				X	
R6	PC					X
R7	UVLS entity					X
R8	PC					X

Guidelines for Requirement R1~~:~~

A UVLS Program may be developed and implemented to either serve as a safety net system protection measure against unforeseen extreme Contingencies or to achieve specific system performance for known transmission Contingencies for which dropping of load is allowed under Transmission Planning (TPL) Reliability Standards. Regardless of the purpose, it is important that the UVLS Program being implemented is effective in terms that it mitigates undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Consideration should be given to voltage set points and time delays, rate of voltage decay or recovery, power flow levels, etc. when designing a UVLS Program.

For the UVLS Program to be effective in achieving its goal, it is also necessary that the UVLS Program is coordinated with generator voltage ride-through capabilities and other protection and control systems that may have an impact on the performance of the UVLS Program. Some of these protection and control systems may include, but are not limited to, transmission line protection, RAS, other undervoltage-based load shedding programs, autoreclosing, and controls of shunt capacitors, reactors, and static ~~var~~voltampere-reactive systems (SVSs).

For example, if the purpose of a UVLS Program is to mitigate fault-induced delayed voltage recovery (FIDVR) events in a large load center that also includes local generation, it is important that such a UVLS Program is coordinated with local generators' voltage ride-through capabilities. Generators in the vicinity of a load center are critical to providing dynamic voltage support to the system during FIDVR events. To maximize the benefit of on-line generation, the best practice may be to shed load prior to generation trip. However, occasionally, it may be best to let generation trip prior to load shed. Therefore, the impact of generation tripping should be considered while designing a UVLS Program.

Another example that can be highlighted is the coordination of a UVLS Program with automatic shunt reactor tripping devices if there are any on the system. Most likely, any shunt reactors on the system will trip off automatically after some time delay during low voltage conditions. In such cases, shunt reactors should be tripped before the load is shed to preserve the system. This may require coordination of time delays associated with the UVLS Program with shunt reactor tripping devices.

~~Examples~~The examples given above demonstrate that, for a UVLS Program to be effective, proper consideration should be given to coordination of a UVLS Program with generator ride-through capabilities and other protection and control systems.

Guidelines for Requirement R2~~:~~

Once a Planning Coordinator (PC) or Transmission Planner (TP) has identified a need for a UVLS Program, the Planning Coordinator or Transmission Planner will develop a program that includes specifications and an implementation schedule, which are then provided to UVLS entities per Requirement R1. Specifications may include voltage set points, time delays, amount of load to be shed, and the location at which load needs to be shed~~, etc~~. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal. The UVLS entity must document that all necessary actions were completed to implement the UVLS Program.

Similarly, when a Corrective Action Plan (CAP) to address UVLS Program deficiencies is developed by the Planning Coordinator or Transmission Planner and provided to UVLS entities per Requirement R5, UVLS entities must comply with the CAP and its associated implementation schedule to ensure that the UVLS Program is effective. The UVLS entity is required to complete the actions specified in the CAP, document the plan implementation, and retain the appropriate evidence to demonstrate implementation and completion.

Deferrals or other relevant changes to the UVLS Program specifications or CAP need to be documented so that the record includes not only what was planned, but what was implemented. Depending on the planning and documentation format used by the responsible entity, evidence of a successful execution could consist of signed-off work orders, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, paid invoices, photographs, walk-through reports, or other evidence.

For example, documentation of a CAP provides an auditable progress and completion confirmation for the identified UVLS Program deficiency:

> **CAP Example 1** - Corrective actions for a quick triggering problem; preemptive actions for similar installations:

The PC or TP obtains fault records from a UVLS entity that participates in its UVLS Program that indicate a group of UVLS relays triggered at the appropriate undervoltage level but with shorter delays than expected. The PC or TP directed the UVLS entity to schedule on-site inspections within three weeks. The results of the inspection confirmed that the delay-time programmed on the relays was 60 cycles instead of 90 cycles. The PC or TP then directed the UVLS entity to correct to a 90-cycle time delay setting of the UVLS relays identified to have shorter time delay settings within eight weeks.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to verify and adjust all remaining UVLS relays time delay settings within a one-year period.

The PC or TP verified completion of verification and adjustment of the time delay settings for all of the UVLS entity's equipment that participates in the PC or TP UVLS Program

CAP Example 2 - Corrective actions for a firmware problem; preemptive actions for similar installations:

The PC or TP obtains fault records on 6/4/2014 from a UVLS entity that participates in its UVLS Program. The UVLS entity also provided the fault records to the manufacturer, who responded on 6/11/2014 that the ~~misoperation~~Misoperation[1] of the UVLS relay was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. The PC or TP approved the UVLS entity's plan to schedule Version 3 firmware installation on 6/12/2014.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to install firmware version 3 at all of the UVLS entity's UVLS relays that are determined to be programmed with version 2 firmware. The completion date was scheduled no-later-than 12/31/2014.

The firmware replacements were completed on 12/4/2014.

Guidelines for Requirement R3~~:~~

In addition to the initial studies required to develop a UVLS Program, periodic comprehensive assessments (detailed analyses) are required to ensure its continued effectiveness. This assessment ~~should~~is required to be completed at least once every 60 calendar months to capture the accumulated

[1] Misoperation of Protection Systems reporting was initiated by the NERC Board of Trustees adopted NERC Rules of Procedure, Section 1600, Request for Data or Information. Refer to: *Request for Data of Information, Protection System Misoperation Data Collection*, August 14, 2014. http://www.nerc.com/pa/RAPA/ProctectionSystem Misoperations/PRC-004-3%20Section%201600%20Data%20Request_20140729.pdf.

effects of minor changes to the system that have occurred since the last assessment was completed. However, at any point in time, a Planning Coordinator or Transmission Planner may also determine that a material change[2] to system topology or operating conditions affects the performance of the UVLS Program and therefore necessitates the same comprehensive assessment. Regardless of the trigger, each assessment should include an evaluation of each UVLS Program to ensure the continued integration through coordination.

This comprehensive assessment supplementscomplements the TPL-001-4 annual assessment requirement to evaluate the impact of protection systems. The 60-month period is the same time frame used in TPL-001-4 and in PRC-006-1.

With respect to situations in which a material change to system and topology or operating conditions would necessitate a comprehensive assessment of the UVLS Program, it is understood that the term material change is not transportable on a continent□wide basis. This determination must be made by the Planning Coordinator or Transmission Planner and should be accompanied by documentation to support the technical rationale for determining material changes.

As specified in Requirement R3, a comprehensive assessment must be performed at least once every 60 calendar months. If a Planning Coordinator or Transmission Planner conducts a comprehensive assessment sooner for the reasons discussed above, the 60-month time period would restart upon completion of this assessment.

Guidelines for Requirement R4:

TheAfter a voltage excursion event, the goal of the assessment required in Requirement R4 is to evaluate: (1) whether the UVLS Program resolved the undervoltage issues for an event that occurred on the system. It is expected that, and (2) the performance of the UVLS Program equipment. The assessment should include event data analysis, such as the relevant sequence of events leading to the undervoltage conditions (e.g., Contingencies, operation of protection systems, and RAS) and field measurements useful to analyzing the behavior of the system. A comprehensive description of the UVLS Program operation should be presented, including conditions of the trigger (e.g., voltage levels, time delays) and amount of load shed for each affected substation. Assessment of the event shall beis performed to evaluate the level of performance of the program for the event of interest and to identify deficiencies to be included in a CAP per Requirement R5. Misoperation of UVLS equipment is addressed as a deficiency. Reporting of UVLS equipment Misoperations are addressed by the NERC *Request for Data and Information, Protection System Misoperation Data Collection*.[3]

The studies and analyses showing the effectiveness of the UVLS Program can be similar to what is required in Requirements R1 and R3, but should include a clear link between the evaluation of

[2] It is understood that the term material change is not transportable on a continent-wide basis. This determination must be made by the Planning Coordinator or Transmission Planner and should be accompanied by documentation to support the technical rationale for determining material changes.
[3] Id.

effectiveness (in studies using simulations) and the analysis of the event (with measurements and event data) that actually occurred. For example, differences between the expected and actual system behavior for the event of interest should be discussed and modeling assumptions should be evaluated. Important discrepancies between the simulations and the actual event should be investigated.

Considering the importance of an event that involves the operation of a UVLS Program, the 12- calendar-month period provides adequate time to analyze the event and perform an assessment while identifying deficiencies within a reasonable time. This time period is also required in PRC- 006-1.

Guidelines for Requirement R5:

Requirement R5 promotes the prudent correction of an identified problem during the assessment ~~evaluations~~ of ~~each~~a UVLS Program. Per Requirements R3 and R4, an assessment of an active UVLS Program is triggered:

- Within 12 calendar months of an event that resulted in a voltage excursion for which the program was designed to operate~~.~~
- At least once every 60 calendar months. The default time frame of 60 calendar months or less between assessments has the intention to assure that the cumulative changes to the network and operating condition affecting the UVLS Program are evaluated~~.~~

Since every UVLS is unique, if material changes are made to system topology or operating conditions, the Planning Coordinator or Transmission Planner will decide the degree to which the change in topology or operating condition becomes a material change sufficient to trigger an assessment of the existing UVLS Program.

A CAP is a list of actions and an associated timetable for implementation to remedy a specific problem. It is a proven tool for resolving operational problems. Per Requirement R5, the Planning Coordinator or Transmission Planner is required to develop a CAP and provide it to UVLS entities to accomplish the purpose of this requirement, which is to prevent future deficiencies in the UVLS Program, thereby minimizing risk to the system. Determining the cause of the deficiency is essential in developing an effective CAP to avoid future re-occurrence of the same problem. A CAP can be revised if additional causes are found.

Based on industry experience and operational coordination timeframes, ~~the drafting team believes that within~~ three calendar months from the date an assessment is completed is a reasonable time frame for development of a CAP, including time to consider alternative solutions and coordination of resources. The “within three calendar months” time frame is solely to develop a CAP, including its implementation schedule, and provide it to UVLS entities. It does not include the time needed for its implementation by UVLS entities. This implementation time frame is dictated within the CAP’s associated timetable for implementation, and the execution of the CAP according to its schedule is required in Requirement R2.

Guidelines for Requirements R6–R8

An accurate UVLS Program database is necessary for the Planning Coordinator or Transmission Planner to perform system reliability assessment studies and event analysis studies. Without accurate data, there is a possibility that annual reliability assessment studies that are performed by the Planning Coordinator or Transmission Planner can lead to erroneous results and therefore impact reliability. Also, without the accurate data, it is very difficult for the Planning Coordinator or Transmission Planner to duplicate a UVLS event and determine the root cause of the problem.

To support a UVLS Program database, it is necessary for each UVLS entity to provide accurate data to its Planning Coordinator. Each UVLS entity will provide the data according to the specified format and schedule provided by the Planning Coordinator. This is required in order for the Planning Coordinator to maintain and support a comprehensive UVLS Program database. By having a comprehensive database, the Planning Coordinator can embark on a reliability assessment or event analysis/benchmarking studies, identify the issues with the UVLS Program, and develop ~~remedial action plans~~Corrective Action Plans.

The UVLS Program database may include, but is not limited to the following:

- Owner and operator of the UVLS Program
- Size and location of customer load, or percent of connected load, to be interrupted

- Corresponding voltage set points and clearing times
- Time delay from initiation to trip signal
- Breaker operating times
- Any other schemes that are part of or impact the UVLS Programs, such as related generation protection, islanding schemes, automatic load restoration schemes, underfrequency load shedding (UFLS~~,~~), and RAS~~.~~

Additionally, the UVLS Program database ~~should~~is required to be updated annually (once every calendar year) by the Planning Coordinator. The intent here is for UVLS entities to review the data annually and provide changes to the Planning Coordinators so that Planning Coordinators can keep the databases current and accurate for performing event analysis and other assessments.

Finally, a Planning Coordinator is required to provide information to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of receipt of a written request. Thirty calendar days was selected as the time frame as it is considered to be reasonable and well-accepted by the industry. Also, this requirement of sharing the database with applicable functional entities supports the directive provided by FERC that requires an integrated and coordinated approach to UVLS programs (Paragraph 1509 of FERC Order No. 693).

~~Version History~~

~~Version~~	~~Date~~	~~Action~~	~~Change Tracking~~
~~0~~	~~April 1, 2005~~	~~Effective Date~~	~~New~~

0	February 8, 2005	Adopted by NERC Board of Trustees	
0	March 16, 2007	Approved by FERC	
0	February 7, 2013	R2 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
0	November 21, 2013	R2 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
1.0	November 13, 2014	Adopted by NERC Board of Trustees	Revisions made under Project 2008-02: Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS) to address directive issued in FERC Order No. 763. Completed revision, merged and updated PRC-010-0, PRC-020-1, PRC-021-1, and PRC-022-1.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Applicability

This standard is applicable to Planning Coordinators and Transmission Planners that have or are developing a UVLS Program, and to Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator. These Distribution Providers and Transmission Owners are referred to as UVLS entities for the purpose of this standard.

The applicability includes both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs.

The phrase "Planning Coordinator or Transmission Planner" provides the latitude for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity.

Rationale for R1

In Paragraph 1509 from Order No. 693, FERC directed NERC to require an integrated and coordinated approach to all protection systems. The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability, and that each Planning Coordinator or Transmission Planner that develops a UVLS Program should evaluate the program's viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage conditions that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. Though presented as separate items, the drafting team recognizes that the studies that show coordination considerations and that the program addresses undervoltage issues may be interrelated and presented as one comprehensive analysis.

In addition, Requirement R1 also requires the Planning Coordinator or Transmission Planner to provide the UVLS Program's specifications and implementation schedule to applicable UVLS entities to implement the program. It is noted that studies to evaluate the effectiveness of the program should be completed prior to providing the specifications and schedule.

Rationale for R2

UVLS entities must implement a UVLS Program or address any necessary corrective actions for a UVLS Program according to the specifications and schedule provided by the Planning Coordinator or Transmission Planner. If UVLS entities do not implement the UVLS Program

according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal.

Rationale for R3

A periodic comprehensive assessment (detailed analysis) should be conducted to identify and catalogue the accumulated effects of minor changes to the system that have occurred since the last assessment was completed, and should include an evaluation of each UVLS Program to ensure the continued integration through coordination. This comprehensive assessment supplements the NERC Reliability Standard TPL-001-4 annual assessment requirement to evaluate the impact of protection systems.

Based on the drafting team's knowledge and experience, and in keeping with time frames contained in similar requirements from other PRC Reliability Standards, 60 calendar months was determined to be the maximum amount of time allowable between assessments. Assessments will be performed sooner than the end of the 60-calendar month period if the Planning Coordinator or Transmission Planner determines that there are material changes to system topology or operating conditions that affect the performance of a UVLS Program. Note that the 60-calendar-month time frame would reset after each assessment.

Rationale for R4

A UVLS Program not functioning as expected during a voltage excursion event for which the UVLS Program was designed to operate presents a critical risk to system reliability. Therefore, a timely assessment to evaluate (1) whether the UVLS Program resolved the undervoltage issues and (2) the performance of the UVLS Program equipment associated with the applicable event is essential. The 12 calendar months (from the date of the event) provides adequate time to coordinate with other Planning Coordinators, Transmission Planners, Transmission Operators, and UVLS entities, simulate pre- and post-event conditions, and complete the performance assessment.

Rationale for R5

If program deficiencies are identified during an assessment ~~of a UVLS Program~~ performed in either Requirement R3 or R4, the Planning Coordinator or Transmission Planner must develop a Corrective Action Plan (CAP) to address the deficiencies. Based on the drafting team's knowledge and experience with UVLS studies, three calendar months was determined to provide a judicious balance between the reliability need to address deficiencies expeditiously and the time needed to consider potential solutions, coordinate resources, develop a CAP and implementation schedule, and provide the CAP and schedule to UVLS entities.

It is noted that the three-month time frame is only to develop the CAP and provide it to UVLS entities and does not encompass the time UVLS entities have to implement the CAP. Requirement R2 requires UVLS entities to execute the CAP according to the schedule provided by the Planning Coordinator or Transmission Planner.

Rationale for R6

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R6 supports this reliability need by requiring the Planning Coordinator to update its UVLS Program database at least once each calendar year.

Rationale for R7

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. -Requirement R7 supports this reliability need by requiring the UVLS entity to provide UVLS Program data in accordance with specified parameters.

Rationale for R8

Requirement R8 supports the integrated and coordinated approach to UVLS programs directed by Paragraph 1509 of Order No. 693 by requiring that UVLS Program data be shared with neighboring Planning Coordinators and Transmission Planners within a reasonable time period. Requests for the database should also be fulfilled for those functional entities that have a reliability need for the data (such as the Transmission Operators that develop System Operating Limits and Reliability Coordinators that develop Interconnection Reliability Operating Limits).

Frequently Asked Questions

To succinctly address common comment themes that require drafting team response on Project 2008-02 UVLS (proposed PRC-010-1), the drafting team provides the following discussion in the construct of an FAQ format.

Introduction

This Frequently Asked Questions (FAQ) document was created during the development of PRC-010-1 (*Undervoltage Load Shedding*)[4,5] to succinctly address common comment themes with respect to the approach and intent of the Project 2008-02 Undervoltage Load Shedding (UVLS)[6] standard drafting team ("drafting team"). This FAQ document is the outcome of comments received during comment periods and multiple outreach sessions with industry. All comments submitted by industry during comment periods may be reviewed on the project page.

Subsequent to the adoption of PRC-010-1, the UVLS drafting team made minor revisions to the standard address the UVLS Misoperation identification and correction.[7] This FAQ document was amended to reflect up the approach and intent of the drafting team during the development of PRC-010-2 concerning Misoperation of UVLS equipment.

Purpose of Standard Revision

1) What is the basis for a revision of the existing UVLS standards?

The initial input into a revision of the existing UVLS standards is FERC Order No. 693,[8] Paragraph 1509, which directed the ERO to develop a modification of PRC-010-0 that "requires that an integrated and coordinated approach be included in all protection systems on the Bulk-Power System, including generators and transmission lines, generators' low voltage ride through capabilities, and UFLS and UVLS programs." In addition, *The Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*[9] ("August 14 Blackout Report") showed that proper coordination would have mitigated effects if UVLS was used as a tool.

[4] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-010-1&title=Undervoltage%20Load%20Shedding.
[5] Adopted by the NERC Board of Trustees on November 14, 2014.
[6] http://www.nerc.com/pa/Stand/Pages/Project-2008-02-Undervoltage-Load-Shedding.aspx
[7] Refer to Project 2010-05.1, which developed PRC-004-3 (Protection System Misoperation Identification and Correction) concurrently with the development of PRC-010-1. (http://www.nerc.com/pa/Stand/Pages/Project 2010-05_Protection_System_Misoperations.aspx).
[8] http://www.nerc.com/docs/docs/ferc/order_693.pdf.
[9] http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf.

Additional inputs included 1) recommendations from the NERC System Protection and Control Subcommittee (SPCS) in its December 2010 *Technical Review of UVLS-Related Standards*[10] to combine the four existing UVLS standards, revise the applicability to entities responsible for UVLS program design, implementation, and coordination, specifically include a requirement for assessment of coordination between UVLS programs and all other protection systems, and differentiate post-event validation of UVLS program design from verifying correct operation of UVLS equipment; 2) the existing UVLS standards were not in the current results-based format; 3) the preceding revision of the underfrequency load shedding (UFLS) standards had similar types of requirements and had been completed under the construct of a consolidation; and 4) the Independent Expert Review Panel recommendations, which included an evaluation of the existing standards' applicability and level of specificity.

The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability. As part of the revision to address this, the drafting team also agreed that an evaluation and consolidation of the existing UVLS standards was necessary to meet current Reliability Standard development initiatives and to provide clear, comprehensive requirements to address the application and coordination of UVLS.

2) UVLS programs are not mandatory—is compliance for an optional tool necessary?

The drafting team asserts that a key takeaway from the August 14 Blackout Report is that coordination of UVLS with other protection systems could have mitigated the effects if UVLS was used as a tool. Although the use of UVLS is not mandatory, if it is determined that this system preservation measure is necessary to support reliability and a UVLS program is installed, the program needs to be properly coordinated, implemented, and assessed due to the inherent associated reliability risks. As such, there needs to be a level of performance required to properly protect system reliability. Of note, PRC-010-1 and PRC-010-2 apply to the defined term "UVLS Program," which limits the standard's applicability to only those undervoltage-based load shedding programs whose performance has an impact on system reliability.[11]

Coordination with Project 2009-03 Emergency Operations

3) EOP-003-2 has potential redundant requirements with proposed PRC-010-1—how is this being addressed?

As part of its five-year review, Project 2009-03 – Emergency Operations (EOP) identified EOP-003-2 (*Load Shedding Plans*),[12] Requirements R2, R4, and R7 as being more properly covered by

[10] http://www.nerc.com/docs/pc/spctf/PRC-010_022%20Report_Approved_20101208.pdf.
[11] The term "UVLS Program" used herein was adopted by the NERC Board of Trustees on November 14, 2014.
[12] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-003-2&title=Load%20Shedding%20Plans.

Project 2008-02 – UVLS. Both projects were strategically coordinated to move in lockstep from a timing perspective to address these requirements. Project 2009-03 – EOP proposed to revise and consolidate EOP-001-2.1b (*Emergency Operations Planning*),[13] EOP-002-3 (Capacity and Energy Emergencies),[14] and EOP-003-2 to create EOP-011-1, will retire the noted EOP-003-2 requirements (among other revisions), and the Project 2008-02 – UVLS *Mapping Document* will show how PRC-010-1 encompasses the retired content accordingly. Slated to have aligning effective dates, both EOP-011-1 (*Emergency Operations*)[15] and PRC-010-1 will be posted and balloted separately but concurrently, so that industry stakeholders will be able to clearly evaluate the transition. Please see the posted Project 2008-02 UVLS Project Coordination Plan for more information.

"UVLS Program" Definition

4) Why is the introduction of the new defined term "UVLS Program" necessary?

The drafting team found it necessary to introduce the term "UVLS Program" for inclusion in the *Glossary of Terms Used in NERC Reliability Standards*[16] ("NERC Glossary") because different types of UVLS systems need to be treated appropriately with respect to reliability requirements. Therefore, the term establishes which UVLS systems PRC-010-1 will apply to an: "automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included."

The definition is meant to inherently exclude locally-applied relays that are designed to protect a contained area or, in other words, are not designed to mitigate wide-area voltage collapse. This exclusion is not explicit in these terms in the enforceable language of the definition since the meaning and measurement of "local" or "wide-area" varies greatly on a continent-wide basis and could potentially be interpreted differently by auditors and the applicable functional entities. Therefore, the definition as written is meant to provide flexibility for the Planning Coordinator or Transmission Planner to determine if a UVLS system falls under the defined term with respect to its impact on the reliability of the BES (voltage instability, voltage collapse, or Cascading). To further support the intended exclusion, further discussion and an example are provided on in the PRC-010-1 and PRC-010-2 Guidelines and Technical Basis section under the heading "Guidelines for UVLS Program Definition."

[13] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-001-2.1b&title=Emergency%20Operations%20Planning.
[14] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-002-3&title=Capacity%20and%20Energy%20Emergencies.
[15] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-011-1&title=Emergency%20Operations.
[16] http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

The definition does explicitly note that the term excludes centrally controlled undervoltage-based load shedding. This type of load shedding is excluded because the drafting team asserts that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with those of a Special Protection System (SPS) or Remedial Action Scheme (RAS) and should therefore be subject to SPS or RAS-related Reliability Standards. See PRC-010-1 and PRC-010-2 Guidelines and Technical Basis section under the heading "Guidelines for UVLS Program Definition" for further discussion.

5) If the definition excludes certain types of UVLS, does this preclude an "integrated" approach (FERC Order No. 693, Paragraph 1509)?

The defined term "UVLS Program" clarifies which UVLS systems are subject to the requirements in PRC-010-1 and PRC-010-2. The resulting exclusions from these versions of the standard do not preclude an "integrated" approach because the standard requires that an entity coordinate with all other protection and control systems as necessary, which may include other types of UVLS (i.e., locally-applied UVLS relays and centrally controlled undervoltage-based load shedding).

6) Where will centrally controlled undervoltage-based load shedding be covered?

As explained immediately above, the Requirements of PRC-010-1 and PRC-010-2 are applicable to the proposed NERC Glossary term "UVLS Program," which excludes centrally controlled undervoltage-based load shedding because its design and characteristics are commensurate with those of an SPS or RAS. However, the NERC Glossary during the development of PRC-010-1 definition of "Special Protection System" excluded UVLS. Therefore, the work under Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems) combined the NERC Glossary definition of "Special Protection System" into the single term "Remedial Action Scheme."[17] The definition revisions specifically excluded UVLS Programs, therefore including centrally controlled undervoltage-based shedding.

Consequently, the introduction of the term "UVLS Program" and the conforming revision to the term "Remedial Action Scheme" explicitly clarifies that RAS-related standards are applicable to centrally controlled undervoltage-based load shedding. The implementation plan for the revised definition of "Remedial Action Scheme" will address entities that will have newly identified RAS resulting from the application of the defined term.

Similar to the coordination effort with Project 2009-03 – EOP explained above, Project 2008-02 – UVLS and Project 2010-05.2 – SPS were coordinated to ensure that the effective dates of the adopted definitions of "Remedial Action Scheme" and "UVLS Program," the PRC-010-1 and PRC-010-1 Reliability Standards, and all associated retirements align.

[17] Adopted by the NERC Board of Trustees on November 14, 2014.

7) Is the term "UVLS Program" inclusive of a collection of independent UVLS relays?

No; multiple independent relays do not constitute a program. While the definition stipulates that a UVLS Program consists of distributed relays and controls, the definition specifies that it must be "[a]n automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System(BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included."

Applicability

8) What is meant by the phrase "Planning Coordinator or Transmission Planner"?

The PRC-010-1 and PRC-010-2 Reliability Standards are applicable to both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs. The phrase "Planning Coordinator or Transmission Planner" provides the flexibility for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity. In addition, the requirements containing this phrase have specific language to qualify the responsible entity. For example, Requirement R1 states: "Each Planning Coordinator or Transmission Planner *that is developing* a UVLS Program shall . . ." This language provides clarity that the applicable entity would be the one that is developing the program.

9) Why is the Transmission Operator not included?

While the Transmission Operator may be involved with UVLS Program activities, the drafting team did not identify any required performance for the Transmission Operator that was necessary to capture within PRC-010-1 and PRC-010-2, since the Transmission Operator does not have the resources necessary to implement program specifications. If responsibilities are delegated to the Transmission Operator by the Transmission Owner, the Transmission Owner is still the accountable party.

To the extent that the Transmission Operator is required to have knowledge of system relays and protection systems, the drafting team notes that this requirement is covered under PRC-001-1.1 (*System Protection Coordination*),[18] Requirement R1. It is also noted that manual load shedding, for which the Transmission Operator is responsible, is not in the purview of PRC-010-1 and PRC-

[18] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-001-1.1&title=System%20Protection%20Coordination.

010-2, as it is covered under current EOP-003-2 and will subsequently be covered by proposed EOP-011-1 (see Project 2009-03 – Emergency Operations).

10) What about UVLS schemes owned by Transmission Owners, Distribution Providers, or Transmission Operators that are not required by the planner?

The PRC-010-1 and PRC-010-2 Reliability Standards are applicable to the term "UVLS Program." The drafting team notes that, by its defining attributes, a UVLS Program would be required and developed by a Planning Coordinator or Transmission Planner. The nature of a UVLS scheme developed or required by a Distribution Provider, Transmission Operator, or Transmission Owner would not meet the attributes of the defined term and would therefore not have the design and characteristics necessary to be subject to the requirements of PRC-010-1 and PRC-010-2.

Requirements R1, R3, R4, and R5

11) What is required to evaluate the coordination referenced in Requirement R1, part 1.2?

Requirement R1 requires each Planning Coordinator or Transmission Planner that develops a UVLS Program to evaluate the program's viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage issues that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. As such, the requirement is meant to provide flexibility for an entity to make the proper determinations, including the considerations for coordination, with respect to program effectiveness based on system characteristics. For further guidance on and examples of coordination considerations, please see the portion of the Guidelines and Technical Basis section under the Requirement R1 heading.

12) Requirements R1, R3, and R4 seem to all require evaluations of program effectiveness—how are they different?

Requirements R1, R3, and R4 do require evaluations of program effectiveness, but they are each at distinct points in time.

Requirement R1 requires evaluation of program effectiveness (by way of the qualifying parts) at the onset of program development, or during the initial planning stage, prior to implementation. Requirement R3 requires the same objectives of an evaluation of effectiveness, but at the point of a mandatory periodic review (at least once every 60 calendar months). Requirement R4 addresses the performance of a UVLS Program after an event (for applicable voltage excursion)

to evaluate whether the UVLS Program resolved the undervoltage issues associated with the event.

It is noted that, because of the separate activities of each requirement, UVLS Program deficiencies found as a result of the assessments performed in Requirement R3 or R4 would not be violations of Requirement R1.

13) Requirement R4 would require the Planning Coordinator or Transmission Planner to review all voltage excursions—isn't this unduly burdensome?

While Requirement R4 essentially requires the Planning Coordinator or Transmission Planner to review all voltage excursions to see if they fall below the initializing set points of the UVLS Program, the drafting team contends that it will be clearly evident if voltage falls below the UVLS threshold because either a) UVLS devices will operate; or b) the system will experience the adverse conditions the UVLS Program was installed to mitigate.

In addition, the drafting team acknowledges that the Planning Coordinator or Transmission Planner may not have the ability to know when voltage excursions are occurring since they are not operating entities. However, a process for the Transmission Operator, Transmission Owner, or Distribution Provider to notify the Transmission Planner or Planning Coordinator of such voltage excursion events is consistent with standard utility practice.

14) PRC-022-1 required the analysis of UVLS Misoperations. How is this addressed in PRC-010-1?

One of the recommendations in the SPCS report was to clearly differentiate between the post-event process of validating the effectiveness of the UVLS program design, its coordination with other protection and control systems, and the potential need to modify the program design (activities addressed in PRC-010-1) and the process of verifying correct operation of UVLS equipment. Because PRC-010-1 was not specific concerning the Misoperation of UVLS equipment, the drafting team made a subsequent revision creating PRC-010-2. Version two (PRC-010-2) now requires that the assessment according to Requirement R4 include the performance (i.e., operation or non-operation) of the UVLS Program equipment.

Relative to the assessment, Requirement R5 requires that a Corrective Action Plan be developed to address any identified deficiencies. This structure ensures that UVLS Program equipment is assessed to identify any Misoperation which could affect BES reliability. Although, the UVLS drafting team maintained during development of PRC-010-1 that verifying correct operation of UVLS equipment should be addressed in PRC-004, the drafting team included UVLS that is intended to trip one or more BES Elements in the proposed PRC-004-5.

Requirements R6, R7, and R8

15) Do Requirements R6, R7, and R8 overlap with the requirements of MOD-032-1?

While both MOD-032-1 (*Data for Power System Modeling and Analysis*)[19] and Requirements R6, R7, and R8 of PRC-010-1 and PRC-010-2 address data requirements, MOD-032-1 establishes overarching modeling data requirements with respect to consistency in format and reporting procedures, whereas the PRC-010-1 and PRC-010-2 requirements address the need to maintain and share data and databases for the purposes of studies for use in event analyses for UVLS Programs specifically. While Reliability Standards in general may have overlap in this manner, the activities in these requirements remain distinctly different.

16) Requirements R6, R7, and R8 appear to be administrative — doesn't this conflict with Paragraph 81 criteria?[20]

Proper maintenance and timely sharing of UVLS Program data as required by Requirements R6, R7, and R8 is necessary to inform the Planning Coordinator or Transmission Planner's studies and analyses. While administrative tasks are required, the tasks have a core reliability-based need.

In addition, Requirements R6, R7, and R8 were written to emulate FERC-approved PRC-006-2 (*Automatic Underfrequency Load Shedding*)[21,22] data requirements. While some of these analogous requirements in PRC-006-2 are listed as candidates for Phase 2 of the Paragraph 81 project, they are not yet approved as meeting the criteria; furthermore, the Independent Expert Review Panel has recommended that these Paragraph 81 candidates not be included for deletion, citing that "there should be a clear expectation for Planning Coordinators to share data necessary to determine their UFLS program parameters."

[19] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=MOD-032-1&title=Data%20for%20Power%20System%20Modeling%20and%20Analysis.
[20] Refer to Standards Independent Expert Review Project (IERP). http://www.nerc.com/pa/Stand/Standard%20Development%20Plan/Standards_Independent_Experts_Review_Project_Report-SOTC_and_Board.pdf.
[21] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-006-2&title=Automatic%20Underfrequency%20Load%20Shedding.
[22] Adopted by the NERC Board of Trustees on November 14, 2014.

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Project 2008-02 Undervoltage Load Shedding (PRC-010-1)

VRF and VSL Justifications

This document provides the Undervoltage Load Shedding Standard Drafting Team's (drafting team's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-010-1 – Undervoltage Load Shedding.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The drafting team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or Cascading failures; or, a requirement in a planning time frame that, if violated, could, under Emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures, place the Bulk Electric System at an unacceptable risk of instability, separation, or Cascading failures, or hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures; or, a requirement in a planning time frame that, if violated, could, under Emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under Emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or Cascading failures nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the Emergency, abnormal, or

restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System or the ability to effectively monitor, control, or restore the Bulk Electric System. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to requirements of reliability standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such requirements must not be watered down to reflect the lower risk level associated with the less important objective of the reliability standard.

The following discussion addresses how the drafting team considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The drafting team believes that Guideline 4 is reflective of the intent of VRFs in the first instance and, therefore, concentrated its approach on the reliability impact of the requirements.

PRC-010-1 – Undervoltage Load Shedding is a standard revision with the stated purpose: *To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs.* FERC Order No. 693 requested that PRC-010-0 be modified to require that an integrated and coordinated approach be included in all protection systems on the Bulk-Power System, including generators and transmission lines, generators' low voltage ride-through capabilities, and underfrequency loading shedding (UFLS) and undervoltage load shedding (UVLS) programs. PRC-010-1 addresses this directive in addition to consolidating and revising PRC-010-0 – Assessment of the Design and Effectiveness of UVLS Program with three (3) other existing UVLS standards: PRC-020-1 – Under-Voltage Load Shedding Program Database, PRC-021-1 – Under-Voltage Load Shedding Program Data, and PRC-022-1 – Under-Voltage Load Shedding Program Performance.

PRC-010-1 has eight (8) requirements that incorporate and enhance the intent of the requirements of PRC-010-0, PRC-020-1, PRC-021-1, and PRC-022-1. The revised standard requires that entities developing an Undervoltage Load Shedding Program (UVLS Program) evaluate the program's effectiveness prior to providing the program specifications and schedule to applicable entities. Applicable entities are then required to adhere to the UVLS Program specifications and implementation schedule, including those specifications and schedules associated with Corrective Action Plans (CAPs) for existing programs. The standard also requires an assessment of a UVLS Program at least once every 60 months, and an assessment to evaluate program performance within 12 months of an applicable event. If program deficiencies are identified as a result of either of these assessments, entities are required to develop and provide a CAP to applicable entities within three (3) months. In addition, there are requirements to update, provide data for, and share a UVLS Program database containing information necessary to model the program for use in event analyses and assessments.

The requirements of PRC-010-1 do not map, one-to-one, with the requirements of the legacy standards. The new requirements comingle various reliability attributes of the legacy standards with new reliability objectives, thus a requirement-to-requirement comparison of VRFs is not always possible. In developing the new VRFs for the requirements of PRC-010-1, the drafting team carefully considered the NERC criteria for developing VRFs, as well as the FERC VRF guidelines. The VRFs of FERC-approved PRC-006-1 – Automatic Underfrequency Load Shedding influenced the drafting team's VRF decisions (citing FERC VRF Guideline 3), as the drafting team used PRC-006-1 as a model with respect to PRC-010-1's language and construct.

NERC Criteria - Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance, and may have only one, two, or three VSLs.

VSLs should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance. The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order on Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

Guideline 2a: A violation of a "binary" type requirement must be a "Severe" VSL.

Guideline 2b: Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF and VSL Justifications – PRC-010-1 Requirement R1	
Proposed VRF	High
NERC VRF Discussion	PRC-010-1 Requirement R1 meets the NERC criterion for a High VRF. Failure to evaluate a UVLS Program to show that it resolves the undervoltage issue it was designed for, and that it is coordinated with generator voltage ride-through capabilities and other protection and control systems, could lead to implementation of an ineffective or counterproductive program. In addition, failure to subsequently provide the UVLS Program specifications and implementation schedule to applicable entities would negate proper program implementation. Both these implications could, under anticipated Emergency, abnormal, or restorative conditions, directly contribute to Bulk Electric System (BES) instability, separation, or Cascading failures.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** PRC-010-1 Requirement R1 has parts that all support the reliability objective so only one VRF was assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	**Guideline 3: Consistency among Reliability Standards** PRC-010-1 Requirement R1 is similar to EOP-003-2, Requirements R3, R4, and R7, which have approved VRFs of High.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R1 meets the NERC criterion for a High VRF. Failure to evaluate a UVLS Program to show that it resolves the undervoltage issue it was designed for, and that it is coordinated with generator voltage ride-through capabilities and other protection and control systems, could lead to implementation of an ineffective or counterproductive program. In addition, failure to subsequently provide the UVLS Program specifications and implementation schedule to applicable entities would negate proper program implementation. Both these implications could, under anticipated Emergency, abnormal, or restorative conditions, directly contribute to BES instability, separation, or Cascading failures.
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** The obligations in PRC-010-1 Requirement R1, which are to evaluate the effectiveness of a UVLS Program according to the criteria specified in the two parts and subsequently provide the program specifications and implementation schedule to applicable entities, are all equally critical elements that failure to meet could, under anticipated Emergency, abnormal, or restorative conditions, directly contribute to BES instability, separation, or

VRF and VSL Justifications – PRC-010-1 Requirement R1	
	Cascading failures. Therefore, the assigned VRF of High is consistent throughout the requirement.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The applicable entity that developed the UVLS Program failed to evaluate the program's effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to UVLS entities in accordance with Requirement R1, including the items specified in parts 1.1 and 1.2.
NERC VSL Guidelines Discussion	The proposed VSL for PRC-010-1 Requirement R1 meets NERC's VSL Guidelines in that there is a binary aspect for failure; the VSL addresses the degrees of compliance with respect to equal importance of the two parts.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** The basis for the current level of compliance in relation to PRC-010-1 Requirement R1 is EOP-003-2 Requirements R3, R4, and R7, as these requirements are being retired because they map to PRC-010-1 Requirement R1. Since the VSL for PRC-010-1 Requirement R1 is binary, the current level of compliance is met or exceeded when compared to the VSLs for EOP-003-2 Requirements R3, R4, and R7.
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** The proposed VSL for PRC-010-1 Requirement R1 is binary and is consistent with the guideline in that it is classified as a severe VSL. **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSL for PRC-010-1 Requirement R1 uses the term "effectiveness" from the associated requirement, which could be considered ambiguous terminology; however, Requirement R1 does qualify the term "effectiveness" by indicating that the applicable entity must include what is listed in the requirement's parts in its evaluation of effectiveness. The VSL subsequently notes that the items specified in the parts must be included. This thereby supports uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-010-1 Requirement R1	
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSL for PRC-010-1 Requirement R1 uses similar terminology to that used in the requirement and is therefore consistent with the requirement.
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSL for PRC-010-1 Requirement R1 is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-010-1 Requirement R2	
Proposed VRF	High
NERC VRF Discussion	PRC-010-1 Requirement R2 meets the NERC criterion for a High VRF. Failure to implement a UVLS Program by adhering to the program specifications and implementation schedule increases the risk that the program will not perform properly. Under anticipated Emergency, abnormal, or restorative conditions, this could directly contribute to BES instability, separation, or Cascading failures.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** PRC-010-1 Requirement R2 has no parts so only one VRF was assigned.
FERC VRF G3 Discussion	**Guideline 3: Consistency among Reliability Standards** PRC-010-1 Requirement R2 is similar to PRC-006-1 Requirement R9 and EOP-003-2 Requirement R5, which have approved VRFs of High.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R2 meets the NERC criterion for a High VRF. Failure to implement a UVLS Program by adhering to the program specifications and implementation schedule increases the risk that the program will not perform properly. Under anticipated Emergency, abnormal, or restorative conditions, this could directly contribute to BES instability, separation, or Cascading failures.
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** The obligations required in PRC-010-1 Requirement R2 are to adhere to the UVLS Program specifications and implementation schedule associated with program development (per Requirement R1) and corrective action (per Requirement R5). The requirement to develop a CAP in Requirement R5 is assigned a Medium VRF; therefore, execution of the corrective actions required by Requirement R2 has a commensurate VRF of Medium. However, since the obligations related to the development of a UVLS Program in Requirement R1 are assigned a High VRF, the failure to implement the program per Requirement R2 could, under anticipated Emergency, abnormal, or restorative conditions, directly contribute to BES instability, separation, or Cascading failures. Therefore, Requirement R2 is assigned a High VRF to reflect the higher risk level associated with the more critical objective.
Proposed Lower VSL	N/A

VRF and VSL Justifications – PRC-010-1 Requirement R2	
Proposed Moderate VSL	N/A
Proposed High VSL	The applicable entity failed to adhere to the UVLS Program specifications in accordance with Requirement R2. OR The applicable entity failed to adhere to the implementation schedule in accordance with Requirement R2.
Proposed Severe VSL	The applicable entity failed to adhere to the UVLS Program specifications and implementation schedule in accordance with Requirement R2.
NERC VSL Guidelines Discussion	PRC-010-1 Requirement R2 meets NERC's VSL Guidelines in that the VSLs cover aspects of the requirement that are equal in importance.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** PRC-010-1 Requirement R2 is a new requirement; therefore, there is no prior level of compliance.
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** N/A **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSLs for PRC-010-1 Requirement R2 do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSLs for PRC-010-1 Requirement R2 use similar terminology to that used in the requirement and are therefore consistent with the requirement.
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSLs for PRC-010-1 Requirement R2 are based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-010-1 Requirement R3	
Proposed VRF	Medium
NERC VRF Discussion	PRC-010-1 Requirement R3 meets NERC's criterion for a Medium VRF. Failure to perform a comprehensive assessment to evaluate the effectiveness of a UVLS Program at least once every 60 calendar months could lead to failure to identify and address a necessary program modification, which could, under anticipated Emergency, abnormal, or restorative conditions, directly and adversely affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, while the performance that must be met when initially developing a UVLS Program is assigned a High VRF in Requirement R1 due to the likely implications of developing and subsequently implementing an ineffective or counterproductive program if the criteria is not met, it is less likely that failure to do a periodic comprehensive assessment of the program, which supplements the annual Transmission Planning (TPL) assessment required by NERC Reliability Standards, would have implications on the BES. Therefore, a violation of Requirement R3 is unlikely to lead to BES instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** PRC-010-1 Requirement R3 has parts that all support the reliability objective so only one VRF was assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	**Guideline 3: Consistency among Reliability Standards** PRC-010-1 Requirement R3 is consistent with the current requirement it is replacing (PRC-010-0 Requirement R1), which has an approved VRF of Medium. Similar performance exists in PRC-006-1 Requirement R4, which has an approved VRF of High. This discrepancy is justified due to the differing nature of the programs these standards are addressing, as PRC-006-1 addresses mandatory UFLS programs and PRC-010-1 covers optional UVLS Programs. A UFLS program inherently has a more likely overall impact on the BES.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R3 meets NERC's criterion for a Medium VRF. Failure to perform a comprehensive assessment to evaluate the effectiveness of a UVLS Program at least once every 60 calendar months could lead to failure to identify and address a necessary program modification, which could, under anticipated Emergency, abnormal, or restorative conditions, directly and

VRF and VSL Justifications – PRC-010-1 Requirement R3	
	adversely affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, while the performance that must be met when initially developing a UVLS Program is assigned a High VRF in Requirement R1 due to the likely implications of developing and subsequently implementing an ineffective or counterproductive program if the criteria is not met, it is less likely that failure to do a periodic comprehensive assessment of the program, which supplements the annual TPL assessment required by NERC Reliability Standards, would have implications on the BES. Therefore, a violation of Requirement R3 is unlikely to lead to BES instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** The obligation required in PRC-010-1 Requirement R3 is to periodically evaluate the effectiveness of a UVLS Program according to the criteria specified in the two parts; the parts are equally critical elements that failure to meet could, under anticipated Emergency, abnormal, or restorative conditions, directly contribute to BES instability, separation, or Cascading failures. However, violation of these commensurate elements is unlikely to lead to BES instability, separation, or Cascading failures. Therefore, the assigned VRF of Medium is consistent throughout the requirement.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The applicable entity failed to perform an assessment at least once during the 60 calendar months in accordance with Requirement R3, including the items specified in parts 3.1 and 3.2.
NERC VSL Guidelines Discussion	PRC-010-1 Requirement R3 meets NERC's VSL Guidelines in that there is a binary aspect for failure; the VSL addresses the degrees of compliance with respect to equal importance of the two parts.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** The proposed VSL for PRC-010-1 Requirement R3 is consistent in nature with the VSL for the requirement it is replacing (PRC-010-0 Requirement R1) and therefore does not lower the current level of compliance.

VRF and VSL Justifications – PRC-010-1 Requirement R3	
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** The proposed VSL for PRC-010-1 Requirement R3 for this binary requirement is consistent with the guideline in that it is classified as a severe VSL. **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSL for PRC-010-1 Requirement R3 does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSL for PRC-010-1 Requirement R3 uses similar terminology to that used in the requirement and is therefore consistent with the requirement.
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSL for PRC-010-1 Requirement R3 is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-010-1 Requirement R4	
Proposed VRF	Medium
NERC VRF Discussion	PRC-010-1 Requirement R4 meets NERC's criterion for a Medium VRF. Failure to perform an assessment to evaluate whether the UVLS Program resolved the undervoltage issues associated with a qualifying event in a timely manner could lead to failure to identify and address a necessary program modification. This could, under anticipated Emergency, abnormal, or restorative conditions, directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, while the performance that must be met when initially developing a UVLS Program is assigned a High VRF in Requirement R1 due to the likely implications of developing and subsequently implementing an ineffective or counterproductive program if the criteria is not met, it is less likely that failure to perform an assessment to evaluate whether the UVLS Program resolved the undervoltage issues associated with a qualifying event would have implications on the BES, as these are infrequent and would be done in addition to the annual TPL assessment required by NERC Reliability Standards. Therefore, a violation of Requirement R4 is unlikely to lead to BES instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** PRC-010-1 Requirement R4 has no parts so only one VRF was assigned.
FERC VRF G3 Discussion	**Guideline 3: Consistency among Reliability Standards** PRC-010-1 Requirement R4 is similar to PRC-022-1 Requirement 1 and PRC-006-1 Requirement R11, which have approved VRFs of Medium.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R4 meets NERC's criterion for a Medium VRF. Failure to perform an assessment to evaluate whether the UVLS Program resolved the undervoltage issues associated with a qualifying event in a timely manner could lead to failure to identify and address a necessary program modification. This could, under anticipated Emergency, abnormal, or restorative conditions, directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, while the performance that must be met when initially developing a UVLS Program is assigned a High VRF in Requirement R1 due to the likely implications of developing and subsequently implementing an ineffective or

VRF and VSL Justifications – PRC-010-1 Requirement R4	
	counterproductive program if the criteria is not met, it is less likely that failure to perform an assessment to evaluate whether the UVLS Program resolved the undervoltage issues associated with a qualifying event would have implications on the BES, as these are infrequent and would be done in addition to the annual TPL assessment required by NERC Reliability Standards. Therefore, a violation of Requirement R4 is unlikely to lead to BES instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** PRC-010-1 Requirement R4 does not co-mingle reliability objectives of differing risk; the assigned VRF of Medium is consistent throughout the requirement.
Proposed Lower VSL	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 12 calendar months but less than or equal to 13 calendar months after an applicable event.
Proposed Moderate VSL	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 13 calendar months but less than or equal to 14 calendar months after an applicable event.
Proposed High VSL	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 14 calendar months but less than or equal to 15 calendar months after an applicable event.
Proposed Severe VSL	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 15 months after an applicable event. OR The applicable entity failed to perform an assessment in accordance with Requirement R4.
NERC VSL Guidelines Discussion	PRC-010-1 Requirement R4 meets NERC's VSL Guidelines in that there is an incremental aspect to the VSLs for tardiness and a binary aspect for failure.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** PRC-010-1 Requirement R4 is different in construct from the requirement it is replacing (PRC-022-1 Requirement R1) and, therefore, the VSLs cannot be compared. However, both sets of VSLs have incremental aspects and a binary aspect for failure.

VRF and VSL Justifications – PRC-010-1 Requirement R4	
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** N/A **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSLs for PRC-010-1 Requirement R4 do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSLs for PRC-010-1 Requirement R4 use similar terminology to that used in the requirement and are therefore consistent with the requirement.
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSLs for PRC-010-1 Requirement R4 are based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-010-1 Requirement R5	
Proposed VRF	Medium
NERC VRF Discussion	PRC-010-1 Requirement R5 meets NERC's criterion for a Medium VRF. Failure to develop and subsequently provide a CAP to address the deficiencies identified as a result of a UVLS Program assessment in a timely manner could lead to failure to address a necessary program modification, which could, under anticipated Emergency, abnormal, or restorative conditions, directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, since the development of a CAP in Requirement R5 is dependent on the outcomes of Requirement R3 or R4, the likelihood of implications on the BES is commensurate with those of Requirements R3 and R4, which are assigned Medium VRFs. Therefore, a violation of Requirement R5 is unlikely to lead to BES instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** PRC-010-1 Requirement R5 has no parts so only one VRF was assigned.
FERC VRF G3 Discussion	**Guideline 3: Consistency among Reliability Standards** PRC-010-1 Requirement R5 is similar to PRC-022-1 Requirement R1.5, which has an approved VRF of Medium.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R5 meets NERC's criterion for a Medium VRF. Failure to develop and subsequently provide a CAP to address the deficiencies identified as a result of a UVLS Program assessment in a timely manner could lead to failure to address a necessary program modification, which could, under anticipated Emergency, abnormal, or restorative conditions, directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, since the development of a CAP in Requirement R5 is dependent on the outcomes of Requirement R3 or R4, the likelihood of implications on the BES is commensurate with those of Requirements R3 and R4, which are assigned Medium VRFs. Therefore, a violation of Requirement R5 is unlikely to lead to BES instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.

VRF and VSL Justifications – PRC-010-1 Requirement R5	
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** PRC-010-1 Requirement R5 does not co-mingle reliability objectives of differing risk; the assigned VRF of Medium is consistent throughout the requirement.
Proposed Lower VSL	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by less than or equal to 15 calendar days.
Proposed Moderate VSL	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 15 calendar days but less than or equal to 30 calendar days.
Proposed High VSL	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 30 calendar days but less than or equal to 45 calendar days.
Proposed Severe VSL	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 45 calendar days. OR The responsible entity failed to develop a Corrective Action Plan or provide it to UVLS entities in accordance with Requirement R5.
NERC VSL Guidelines Discussion	PRC-010-1 Requirement R5 meets NERC's VSL Guidelines in that there is an incremental aspect to the VSLs for tardiness and a binary aspect for failure.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** PRC-010-1 Requirement R5 is different in construct from the requirement it is replacing (PRC-022-1 Requirement R1) and, therefore, the VSLs cannot be compared. However, both sets of VSLs have incremental aspects and a binary aspect for failure.
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** N/A **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSLs for PRC-010-1 Requirement R5 do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-010-1 Requirement R5	
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSLs for PRC-010-1 Requirement R5 use similar terminology to that used in the requirement and are therefore consistent with the requirement.
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSLs for PRC-010-1 Requirement R5 are based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-010-1 Requirement R6	
Proposed VRF	Lower
NERC VRF Discussion	PRC-010-1 Requirement R6 meets NERC's criterion for a Lower VRF. Though having a current UVLS Program database is necessary to properly inform accurate undervoltage studies and event analyses, this is a planning requirement that is administrative in nature; failure to annually update a UVLS Program database would not, under the anticipated Emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** The requirement has no parts so only one VRF was assigned.
FERC VRF G3 Discussion	**Guideline 3: Consistency among Reliability Standards** PRC-010-1 Requirement R6 similar to PRC-006-1 Requirement R6, which has an approved VRF of Lower.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R6 meets NERC's criterion for a Lower VRF. Though having a current UVLS Program database is necessary to properly inform accurate undervoltage studies and event analyses, this is a planning requirement that is administrative in nature; failure to annually update a UVLS Program database would not, under the anticipated Emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** PRC-010-1 Requirement R6 does not co-mingle reliability objectives of differing risk; the assigned VRF of Lower is consistent throughout the requirement.
Proposed Lower VSL	The applicable entity updated the database in accordance with Requirement R6 but was late by less than or equal to 30 calendar days.
Proposed Moderate VSL	The applicable entity updated the database in accordance with Requirement R6 but was late by less than or equal to 30 calendar days.
Proposed High VSL	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 60 calendar days but less than or equal to 90

VRF and VSL Justifications – PRC-010-1 Requirement R6	
	calendar days.
Proposed Severe VSL	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 90 calendar days. OR The applicable entity failed to update the database in accordance with Requirement R6.
NERC VSL Guidelines Discussion	PRC-010-1 Requirement R6 meets NERC's VSL Guidelines in that there is an incremental aspect to the VSLs for tardiness and a binary aspect for failure.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** PRC-010-1 Requirement R6 is replacing PRC-020-1 Requirement R1, which is applicable to the Regional Reliability Organization and has no associated VSLs. Therefore, there is no prior level of compliance.
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** N/A **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSLs for PRC-010-1 Requirement R6 do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSLs for PRC-010-1 Requirement R6 use similar terminology to that used in the requirement and are therefore consistent with the requirement.
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSLs for PRC-010-1 Requirement R6 are based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-010-1 Requirement R7	
Proposed VRF	Lower
NERC VRF Discussion	PRC-010-1 Requirement R7 meets NERC's criterion for a Lower VRF. Though providing current and formatted data is necessary to properly support a UVLS Program database, which subsequently informs accurate undervoltage studies and event analyses, this is a planning requirement that is administrative in nature; failure to provide the data according to the format and schedule specified would not, under the anticipated Emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** PRC-010-1 Requirement R7 has no parts so only one VRF was assigned.
FERC VRF G3 Discussion	**Guideline 3 Consistency among Reliability Standards:** PRC-010-1 Requirement R7 is similar to PRC-006-1 Requirement R8, which has an approved VRF of Lower.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R7 meets NERC's criterion for a Lower VRF. Though providing current and formatted data is necessary to properly support a UVLS Program database, which subsequently informs accurate undervoltage studies and event analyses, this is a planning requirement that is administrative in nature; failure to provide the data according to the format and schedule specified would not, under the anticipated Emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** PRC-010-1 Requirement R7 does not co-mingle reliability objectives of differing risk; the assigned VRF of Lower is consistent throughout the requirement.
Proposed Lower VSL	The applicable entity provided data in accordance with Requirement R7 but was late by less than or equal to 30 calendar days per the specified schedule. OR

VRF and VSL Justifications – PRC-010-1 Requirement R7	
	The applicable entity provided data in accordance with Requirement R7 but the data was not provided according to the specified format.
Proposed Moderate VSL	The applicable entity provided data in accordance with Requirement R7 but was late by more than 30 calendar days but less than or equal to 60 calendar days per the specified schedule.
Proposed High VSL	The applicable entity provided data in accordance with Requirement R7 but was late by more than 60 calendar days but less than or equal to 90 calendar days per the specified schedule.
Proposed Severe VSL	The applicable entity provided data in accordance with Requirement R7 but was late by more than 90 calendar days per the specified schedule. OR The applicable entity failed to provide data in accordance with Requirement R7.
NERC VSL Guidelines Discussion	PRC-010-1 Requirement R7 meets NERC's VSL Guidelines in that the VSLs cover aspects of the requirement that are not equal in importance; there is an incremental aspect to the VSLs for tardiness and a binary aspect for failure.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** PRC-010-1 Requirement R7 is different in construct from the requirement it is replacing (PRC-021-1 Requirement R1) and, therefore, the VSLs cannot be compared. However, both sets of VSLs have incremental aspects and a binary aspect for failure.
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** N/A **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSLs for PRC-010-1 Requirement R7 do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSLs for PRC-010-1 Requirement R7 use similar terminology to that used in the requirement and are therefore consistent with the requirement.

VRF and VSL Justifications – PRC-010-1 Requirement R7	
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSLs for PRC-010-1 Requirement R7 are based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-010-1 Requirement R8	
Proposed VRF	Lower
NERC VRF Discussion	PRC-010-1 Requirement R8 meets NERC's criterion for a Lower VRF. Though sharing a UVLS Program database with applicable entities in a timely manner supports an integrated and coordinated approach to UVLS programs, this is a planning requirement that is administrative in nature; failure to share the database within 30 calendar days of a request would not, under the anticipated Emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G1 Discussion	**Guideline 1: Consistency w/ Blackout Report** N/A
FERC VRF G2 Discussion	**Guideline 2: Consistency within a Reliability Standard** The requirement has no parts so only one VRF was assigned.
FERC VRF G3 Discussion	**Guideline 3: Consistency among Reliability Standards** PRC-010-1 Requirement R8 is similar to PRC-006-1 Requirement R7, which has an approved VRF of Lower.
FERC VRF G4 Discussion	**Guideline 4: Consistency with NERC Definitions of VRFs** PRC-010-1 Requirement R8 meets NERC's criterion for a Lower VRF. Though sharing a UVLS Program database with applicable entities in a timely manner supports an integrated and coordinated approach to UVLS programs, this is a planning requirement that is administrative in nature; failure to share the database within 30 calendar days of a request would not, under the anticipated Emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. The applicable entities are always responsible for maintaining the reliability of the BES regardless of the situation.
FERC VRF G5 Discussion	**Guideline 5: Treatment of Requirements that Co-mingle More than One Obligation** PRC-010-1 Requirement R8 does not co-mingle reliability objectives of differing risk; the assigned VRF of Lower is consistent throughout the requirement.
Proposed Lower VSL	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by less than or equal to 15 calendar days.
Proposed Moderate VSL	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 15 calendar days but less than or equal to 30 calendar days.

VRF and VSL Justifications – PRC-010-1 Requirement R8	
Proposed High VSL	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 30 calendar days but less than or equal to 45 calendar days.
Proposed Severe VSL	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 45 calendar days. OR The applicable entity failed to provide its UVLS Program database in accordance with Requirement R8.
NERC VSL Guidelines Discussion	PRC-010-1 Requirement R8 meets NERC's VSL Guidelines in that there is an incremental aspect to the VSLs for tardiness and a binary aspect for failure.
FERC VSL G1 Discussion	**Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance** PRC-010-1 Requirement R8 is replacing PRC-020-1 Requirement R2, which is applicable to the Regional Reliability Organization and has no associated VSLs. Therefore, there is no prior level of compliance.
FERC VSL G2 Discussion	**Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties** **Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent** N/A **Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language** The proposed VSLs for PRC-010-1 Requirement R8 do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	**Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement** The proposed VSLs for PRC-010-1 Requirement R8 use similar terminology to that used in the requirement and are therefore consistent with the requirement.
FERC VSL G4	**Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations** The proposed VSLs for PRC-010-1 Requirement R8 are based on a single violation and not cumulative violations.

Mapping Document

Project 2008-02.2 Phase 2: Undervoltage Load Shedding

During development of PRC-010-1, the standard drafting team provided the following explanation on its approach to cover Misoperation of UVLS equipment in future work:

> "As PRC-022-1 addresses UVLS equipment Misoperations, the UVLS drafting team's intention is for PRC-004 to address Misoperations of UVLS Program equipment. A change to make PRC-004 explicitly applicable to UVLS Program equipment will be addressed once PRC-004-3 – Protection System Misoperation Identification and Correction[1] is completed under Project 2010-05.1 – Misoperations (Phase 1 of Protection Systems)."

Table demonstrates how proposed changes map from the retirement of PRC-022-1 (retired by the initial 2008-02 project) to the proposed PRC-010-2. The revisions are being proposed to provide additional clarity with the aligning revisions being proposed in PRC-004-5 as shown in Table 2.

[1] PRC-004-3 was surpassed by version four which addressed applicability to dispersed generation resources under Project 2014-01.

Table 1: Mapping PRC-022-1 to PRC-010-2		
Requirement in Approved PRC-022-1 Reliability Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-010-2 or Comments**
R1. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall **analyze and document all UVLS operations and Misoperations**. The analysis shall include:* **R1.5** For any Misoperation, a Corrective Action Plan to avoid future Misoperations of a similar nature. *Sub-requirements R1.1 through R1.4 have been omitted because they were addressed in Project 2008-02 during development of PRC-010-1.	PRC-010-2 proposes Part 4.2 to provide additional clarity that UVLS equipment operations and Misoperations are addressed by Requirement R4 through the Planning Coordinator or Transmission Planner assessment. Part 4.1 was originally embedded in the main Requirement R4 of PRC-010-1 and is now shown as a new Part 4.1 now. Part 4.2 is being proposed to provide the necessary clarity that the assessment conducted following an event that resulted in a voltage excursion for which its UVLS Program was designed to operate must include UVLS Program equipment.	**R4.** Each Planning Coordinator or Transmission Planner shall, within 12 calendar months of an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, perform an assessment to evaluate: **4.1.** whether its UVLS Program resolved the undervoltage issues associated with the event, and **(Proposed) 4.2.** the performance (i.e., operation and non-operation) of the UVLS Program equipment.

Table 1: Mapping PRC-022-1 to PRC-010-2		
Requirement in Approved PRC-022-1 Reliability Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-010-2 or Comments**
	Part 4.2 requires the Planning Coordinator or Transmission Planner to assess the UVLS equipment performance and address any deficiencies in a Corrective Action Plan (CAP) as required by PRC-010-2, Requirement R5. The clause "in its UVLS Program" was removed to clarify the Corrective Action Plan is addressing components of the assessment, which is about the UVLS Program.	**R5.** Each Planning Coordinator or Transmission Planner that identifies deficiencies during an assessment performed in either Requirement R3 or R4 shall develop a Corrective Action Plan to address the deficiencies and subsequently provide the Corrective Action Plan, including an implementation schedule, to UVLS entities within three calendar months of completing the assessment. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

Table 2: Mapping PRC-004-5		
Requirement in Approved PRC-022-1 Reliability Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-5 or Comments**
R1. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall **analyze and document all UVLS operations and Misoperations**. The analysis shall include:* **R1.5** For any Misoperation, a Corrective Action Plan to avoid future Misoperations of a similar nature. *Sub-requirements R1.1 through R1.4 have been omitted because they were addressed in Project 2008-02 during development of PRC-010-1.	Applicability 4.2.3 addresses the clause "analyze and document all UVLS operations and Misoperations."	**4.2.3** Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Physical Security Directives
CIP-014-2

Standards Involved

Approval:

- CIP-014-2 – Physical Security

Retirement:

- CIP-014-1 – Physical Security

Prerequisite Approvals:

N/A

Background

In Order No. 802 (final order on CIP-014-1 – Physical Security), issued on November 20, 2014, FERC directed NERC to remove the term "widespread" from Reliability Standard CIP-014-1 or, alternatively, to propose modifications to the Reliability Standard that address the Commission's concerns. FERC directed that NERC submit a responsive modification within six months from the effective date of this final rule.

Effective Date

CIP-014-2 shall become effective on the later of the first day following the Effective Date of CIP-014-1 or the first day after CIP-014-2 is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, CIP-014-2 shall become effective on the later of the first day following the Effective Date of CIP-014-1 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction

Retirement of Existing Standards:

The existing standard, CIP-014-1, shall be retired at midnight of the day immediately prior to the effective date of CIP-014-2 in the particular jurisdiction in which the revised standard is becoming effective.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Transmission Operator

Implementation of CIP-014-1

All aspects of the Implementation Plan for CIP-014-1 will remain applicable to CIP-014-2 and are incorporated here by reference.

Cross References

The Implementation Plan for CIP-014-1 is available here.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. A revised SAR was approved by the Standards Committee on December 9, 2014 to address the directives issued in FERC Order No. 802 issued on November 20, 2014, in Docket No. RD14-15-000, *Physical Security Reliability Standard*, 146 FERC ¶ 61,140 (2014). The appointed Physical Security Standard Drafting Team made the revisions to the standard.

Description of Current Draft

This is the first draft of the proposed Reliability Standard, and it is being posted for a 45-day comment and concurrent initial ballot period. This draft includes proposed revisions to address the directives issued in FERC Order No. 802.

Anticipated Actions	Anticipated Date
45-day Comment and Initial Ballot.	February-March, 2015
10-day Final Ballot.	April, 2015
BOT Adoption.	May, 2015
File with applicable Regulatory Authorities.	June, 2015

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the NERC Glossary of Terms used in Reliability Standards (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None

A. Introduction

1. Title: Physical Security

2. Number: CIP-014-1

3. Purpose: To identify and protect Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection.

4. Applicability:

4.1. Functional Entities:

4.1.1 Transmission Owner that owns a Transmission station or Transmission substation that meets any of the following criteria:

4.1.1.1 Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

4.1.1.2 Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

4.1.1.3 Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or

Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

4.1.1.4 Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

4.1.2 Transmission Operator.

Exemption: Facilities in a "protected area," as defined in 10 C.F.R. § 73.2, within the scope of a security plan approved or accepted by the Nuclear Regulatory Commission are not subject to this Standard; or, Facilities within the scope of a security plan approved or accepted by the Canadian Nuclear Safety Commission are not subject to this Standard.

5. Effective Dates:

See Implementation Plan for CIP-014-2.

6. Background:

This Reliability Standard addresses the directives from the FERC order issued March 7, 2014, *Reliability Standards for Physical Security Measures*, 146 FERC ¶ 61,166 (2014), which required NERC to develop a physical security reliability standard(s) to identify and protect facilities that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

B. Requirements and Measures

R1. Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. *[VRF: High; Time-Horizon: Long-term Planning]*

1.1. Subsequent risk assessments shall be performed:

- At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection; or

- At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

1.2. The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.

M1. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the risk assessment of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria in Applicability Section 4.1.1 as specified in Requirement R1. Additionally, examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the identification of the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment as specified in Requirement R1, Part 1.2.

Rationale for Requirement R1:

This requirement meets the FERC directive from paragraph 6 of its March 7, 2014 order on physical security to perform a risk assessment to identify which facilities if rendered inoperable or damaged could impact an Interconnection through instability, uncontrolled separation, or cascading failures. The requirement is not to require identification of, and thus, not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

Requirement R1 also meets the FERC directive for periodic reevaluation of the risk assessment by requiring the risk assessment to be performed every 30 months (or 60 months for an entity that has not identified in a previous risk assessment).

After identifying each Transmission station and Transmission substation that meets the criteria in Requirement R1, it is important to additionally identify the primary control center that operationally controls that Transmission station or Transmission substation (*i.e.,* the control center whose electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker, compared to a control center that only has the ability to monitor the Transmission station and Transmission substation and, therefore, must coordinate direct physical action through another entity).

R2. Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with or after the risk assessment performed under Requirement R1. *[VRF: Medium; Time-Horizon: Long-term Planning]*

2.1. Each Transmission Owner shall select an unaffiliated verifying entity that is either:

- A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or

- An entity that has transmission planning or analysis experience.

2.2. The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90 calendar days following the completion of the Requirement R1 risk assessment.

2.3. If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation:

- Modify its identification under Requirement R1 consistent with the recommendation; or

- Document the technical basis for not modifying the identification in accordance with the recommendation.

2.4. Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M2. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner completed an unaffiliated third party verification of the Requirement R1 risk assessment and satisfied all of the applicable provisions of Requirement R2, including, if applicable, documenting the technical basis for not modifying the Requirement R1 identification as specified under Part 2.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 2.4.

Rationale for Requirement R2:

This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring verification by an entity other than the owner or operator of the risk assessment performed under Requirement R1.

This requirement provides the flexibility for a Transmission Owner to select registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The

term “unaffiliated” means that the selected verifying entity cannot be a corporate affiliate (*i.e.*, the verifying entity cannot be an entity that controls, is controlled by, or is under common control with, the Transmission owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit. The term “unaffiliated” is not intended to prohibit a governmental entity from using another government entity to be a verifier under Requirement R2.

Requirement R2 also provides the Transmission Owner the flexibility to work with the verifying entity throughout the Requirement R1 risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could coordinate with their unaffiliated verifying entity to perform a Requirement R1 risk assessment to satisfy both Requirement R1 and Requirement R2 concurrently.

Planning Coordinator is a functional entity listed in Part 2.1. The Planning Coordinator and Planning Authority are the same entity as shown in the NERC Glossary of Terms Used in NERC Reliability Standards.

R3. For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the primary control center of such identification and the date of completion of Requirement R2. *[VRF: Lower; Time-Horizon: Long-term Planning]*

3.1. If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.

M3. Examples of acceptable evidence may include, but are not limited to, dated written or electronic notifications or communications that the Transmission Owner notified each Transmission Operator, as applicable, according to Requirement R3.

Rationale for Requirement R3:

Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first identifying which Transmission stations and Transmission substations meet the criteria specified by Requirement R1, as verified according to Requirement R2. This requirement is intended to ensure that a Transmission

Operator that has operational control of a primary control center identified in Requirement R1, Part 1.2 of a Transmission station or Transmission substation verified according to Requirement R2 receives notice of such identification so that the Transmission Operator may timely fulfill its resulting obligations under Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include notice of the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or the verification process under Requirement R2.

R4. Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following: *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]*

4.1. Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s);

4.2. Prior history of attack on similar facilities taking into account the frequency, geographic proximity, and severity of past physical security related events; and

4.3. Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.

M4. Examples of evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner or Transmission Operator conducted an evaluation of the potential threats and vulnerabilities of a physical attack to their respective Transmission station(s), Transmission substation(s) and primary control center(s) as specified in Requirement R4.

Rationale for Requirement R4:

This requirement meets the FERC directive from paragraph 8 in the order on physical security that the reliability standard must require tailored evaluation of potential threats and vulnerabilities to facilities identified in Requirement R1 and verified according to Requirement R2. Threats and vulnerabilities may vary from facility to facility based on factors such as the facility's location, size, function,

existing protections, and attractiveness of the target. As such, the requirement does not mandate a one-size-fits-all approach but requires entities to account for the unique characteristics of their facilities.

Requirement R4 does not explicitly state when the evaluation of threats and vulnerabilities must occur or be completed. However, Requirement R5 requires that the entity's security plan(s), which is dependent on the Requirement R4 evaluation, must be completed within 120 calendar days following completion of Requirement R2. Thus, an entity has the flexibility when to complete the Requirement R4 evaluation, provided that it is completed in time to comply with the requirement in Requirement R5 to develop a physical security plan 120 calendar days following completion of Requirement R2.

R5. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s). The physical security plan(s) shall be developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: *[VRF: High; Time-Horizon: Long-term Planning]*

5.1. Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.

5.2. Law enforcement contact and coordination information.

5.3. A timeline for executing the physical security enhancements and modifications specified in the physical security plan.

5.4. Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).

M5. Examples of evidence may include, but are not limited to, dated written or electronic documentation of its physical security plan(s) that covers their respective identified and verified Transmission station(s), Transmission substation(s), and primary control center(s) as specified in Requirement R5, and additional evidence demonstrating execution of the physical security plan according to the timeline specified in the physical security plan.

Rationale for Requirement R5:

This requirement meets the FERC directive from paragraph 9 in the order on physical security requiring the development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

R6. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5. *[VRF: Medium; Time-Horizon: Long-term Planning]*

6.1. Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following:

- An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.
- An entity or organization approved by the ERO.
- A governmental agency with physical security expertise.
- An entity or organization with demonstrated law enforcement, government, or military physical security expertise.

6.2. The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5.

6.3. If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:

- Modify its evaluation or security plan(s) consistent with the recommendation; or
- Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation.

6.4. Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M6. Examples of evidence may include, but are not limited to, written or electronic documentation that the Transmission Owner or Transmission Operator had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 as specified in Requirement R6 including, if applicable, documenting the reasons for not modifying the evaluation or security plan(s) in accordance with a recommendation under Part 6.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 6.4.

Rationale for Requirement R6:

This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring review by an entity other than the owner or operator with appropriate expertise of the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5.

As with the verification required by Requirement R2, Requirement R6 provides Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout the Requirement R4 evaluation and the development of the Requirement R5 security plan(s). This would allow entities to satisfy their obligations under Requirement R6 concurrent with the satisfaction of their obligations under Requirements R4 and R5.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence during an on-site visit to show that it was compliant for the full time period since the last audit.

The Transmission Owner and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation.

The responsible entities shall retain documentation as evidence for three years.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records, subject to the confidentiality provisions of Section 1500 of the Rules of Procedure and the provisions of Section 1.4 below.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

Confidentiality: To protect the confidentiality and sensitive nature of the evidence for demonstrating compliance with this standard, all evidence will be retained at the Transmission Owner's and Transmission Operator's facilities.

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**High**	The Transmission Owner performed an initial risk assessment but did so after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to two calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability,	The Transmission Owner performed an initial risk assessment but did so more than two calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to four calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could	The Transmission Owner performed an initial risk assessment but did so more than four calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to six calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability,	The Transmission Owner performed an initial risk assessment but did so more than six calendar months after the date specified in the implementation plan for performing the initial risk assessment; OR The Transmission Owner failed to perform an initial risk assessment; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 30 calendar months but less than or equal to 32 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a	result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 32 calendar months but less than or equal to 34 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a	uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 34 calendar months but less than or equal to 36 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk	Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			subsequent risk assessment but did so after 60 calendar months but less than or equal to 62 calendar months.	subsequent risk assessment but did so after 62 calendar months but less than or equal to 64 calendar months.	assessment but did so after 64 calendar months but less than or equal to 66 calendar months; OR The Transmission Owner performed a risk assessment but failed to include Part 1.2.	Cascading within an Interconnection failed to perform a risk assessment; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 66 calendar months; OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						The Transmission Owner that has not identified in its previous risk assessment any Transmission station and Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a subsequent risk assessment.
R2	**Long-term Planning**	**Medium**	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so in more than 90 calendar days but less than or equal to 100 calendar days	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 100 calendar days but less than or equal to 110 calendar days	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 110 calendar days but less than or equal to 120 calendar days	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 120 calendar days following

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 60 calendar days and less than or equal to 70 calendar days from completion of the third party verification.	following completion of Requirement R1; Or The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 70 calendar days and less than or equal to 80 calendar days from completion of the third party verification.	following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 80 calendar days from completion of the third party verification; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1	completion of Requirement R1; OR The Transmission Owner failed to have an unaffiliated third party verify the risk assessment performed under Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to implement procedures for protecting information per Part 2.4.

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					but failed to modify or document the technical basis for not modifying its identification under R1 as required by Part 2.3.	
R3	**Long-term Planning**	**Lower**	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than seven calendar days and less than or equal to nine calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than nine calendar days and less than or equal to 11 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 11 calendar days and less than or equal to 13 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 13 calendar days following the completion of Requirement R2; OR The Transmission Owner failed to notify the Transmission Operator that it operates a control

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			control center of the removal from the identification in Requirement R1 but did so more than seven calendar days and less than or equal to nine calendar days following the verification or the subsequent risk assessment.	control center of the removal from the identification in Requirement R1 but did so more than nine calendar days and less than or equal to 11 calendar days following the verification or the subsequent risk assessment.	the identification in Requirement R1 but did so more than 11 calendar days and less than or equal to 13 calendar days following the verification or the subsequent risk assessment.	center identified in Requirement R1; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 13 calendar days following the verification or the subsequent risk assessment. OR The Transmission Owner failed to notify the Transmission Operator that operates the primary control center of the removal from the

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						identification in Requirement R1.
R4	**Operations Planning, Long-term Planning**	**Medium**	N/A	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider one of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider two of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity failed to conduct an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1; OR The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						substation(s), and primary control center(s) identified in Requirement R1 but failed to consider Parts 4.1 through 4.3.
R5	**Long-term Planning**	**High**	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 120 calendar days but less than or equal to 130 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 130 calendar days but less than or equal to 140 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 140 calendar days but less than or equal to 150 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 150 calendar days after completing the verification in Requirement R2; OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include one of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include two of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include three of Parts 5.1 through 5.4 in the plan.	The Responsible Entity failed to develop and implement a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						center(s) identified in Requirement R1 and verified according to Requirement 2 but failed to include Parts 5.1 through 5.4 in the plan.
R6	**Long-term Planning**	**Medium**	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 90 calendar days but less than or equal to 100 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 100 calendar days but less than or equal to 110 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so more than 110 calendar days but less than or equal to 120 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed	The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 in more than 120 calendar days; OR The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 60 calendar days and less than or equal to 70 calendar days following completion of the third party review.	under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 70 calendar days and less than or equal to 80 calendar days following completion of the third party review.	under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 80 calendar days following completion of the third party review; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did not document the reason for not modifying the security plan(s) as specified in Part 6.3.	the security plan(s) developed under Requirement R5; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but failed to implement procedures for protecting information per Part 6.3.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Section 4 Applicability

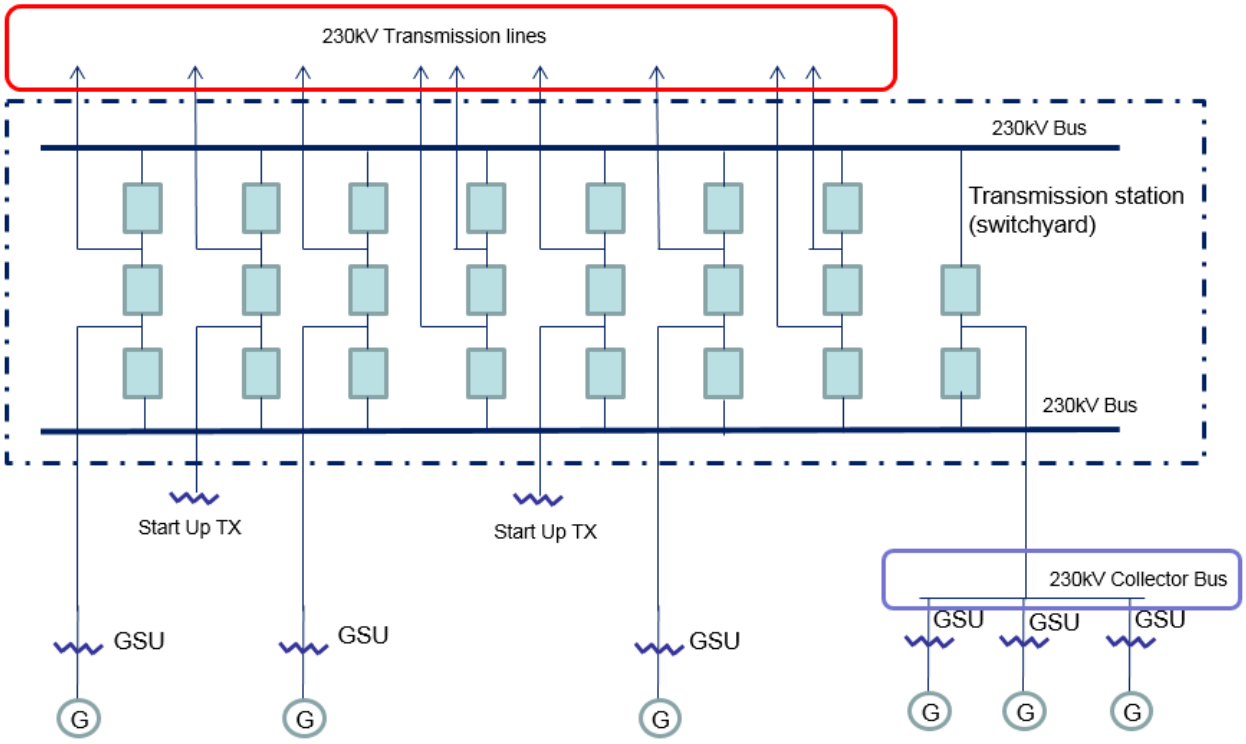
The purpose of Reliability Standard CIP-014 is to protect Transmission stations and Transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. To properly include those entities that own or operate such Facilities, the Reliability Standard CIP-014 first applies to Transmission Owners that own Transmission Facilities that meet the specific criteria in Applicability Section 4.1.1.1 through 4.1.1.4. The Facilities described in Applicability Section 4.1.1.1 through 4.1.1.4 mirror those Transmission Facilities that meet the bright line criteria for "Medium Impact" Transmission Facilities under Attachment 1 of Reliability Standard CIP-002-5.1. Each Transmission Owner that owns Transmission Facilities that meet the criteria in Section 4.1.1.1 through 4.1.1.4 is required to perform a risk assessment as specified in Requirement R1 to identify its Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. The Standard Drafting Team (SDT) expects this population will be small and that many Transmission Owners that meet the applicability of this standard will not actually identify any such Facilities. Only those Transmission Owners with Transmission stations or Transmission substations identified in the risk assessment (and verified under Requirement R2) have performance obligations under Requirements R3 through R6.

This standard also applies to Transmission Operators. A Transmission Operator's obligations under the standard, however, are only triggered if the Transmission Operator is notified by an applicable Transmission Owner under Requirement R3 that the Transmission Operator operates a primary control center that operationally controls a Transmission station(s) or Transmission substation(s) identified in the Requirement R1 risk assessment. A primary control center operationally controls a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical action at the identified Transmission station or Transmission substation, such as opening a breaker, as opposed to a control center that only has information from the Transmission station or Transmission substation and must coordinate direct action through another entity. Only Transmission Operators who are notified that they have primary control centers under this standard have performance obligations under Requirements R4 through R6. In other words, primary control center for purposes of this Standard is the control center that the Transmission Owner or Transmission Operator, respectively, uses as its primary, permanently-manned site to physically operate a Transmission station or Transmission substation that is identified in Requirement R1 and verified in Requirement R2. Control centers that provide back-up capability are not applicable, as they are a form of resiliency and intentionally redundant.

The SDT considered several options for bright line criteria that could be used to determine applicability and provide an initial threshold that defines the set of Transmission stations and Transmission substations that would meet the directives of the FERC order on physical security (*i.e.*, those that could cause instability, uncontrolled separation, or Cascading within an

Interconnection). The SDT determined that using the criteria for Medium Impact Transmission Facilities in Attachment 1 of CIP-002-5.1 would provide a conservative threshold for defining which Transmission stations and Transmission substations must be included in the risk assessment in Requirement R1 of CIP-014. Additionally, the SDT concluded that using the CIP-002-5.1 Medium Impact criteria was appropriate because it has been approved by stakeholders, NERC, and FERC, and its use provides a technically sound basis to determine which Transmission Owners should conduct the risk assessment. As described in CIP-002-5.1, the failure of a Transmission station or Transmission substation that meets the Medium Impact criteria could have the capability to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). The SDT understands that using this bright line criteria to determine applicability may require some Transmission Owners to perform risk assessments under Requirement R1 that will result in a finding that none of their Transmission stations or Transmission substations would pose a risk of instability, uncontrolled separation, or Cascading within an Interconnection. However, the SDT determined that higher bright lines could not be technically justified to ensure inclusion of all Transmission stations and Transmission substations, and their associated primary control centers that, if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. Further guidance and technical basis for the bright line criteria for Medium Impact Facilities can be found in the Guidelines and Technical Basis section of CIP-002-5.1.

Additionally, the SDT determined that it was not necessary to include Generator Operators and Generator Owners in the Reliability Standard. First, Transmission stations or Transmission substations interconnecting generation facilities are considered when determining applicability. Transmission Owners will consider those Transmission stations and Transmission substations that include a Transmission station on the high side of the Generator Step-up transformer (GSU) using Applicability Section 4.1.1.1 and 4.1.1.2. As an example, a Transmission station or Transmission substation identified as a Transmission Owner facility that interconnects generation will be subject to the Requirement R1 risk assessment if it operates at 500kV or greater or if it is connected at 200 kV – 499kV to three or more other Transmission stations or Transmission substations and has an "aggregate weighted value" exceeding 3000 according to the table in Applicability Section 4.1.1.2. Second, the Transmission analysis or analyses conducted under Requirement R1 should take into account the impact of the loss of generation connected to applicable Transmission stations or Transmission substations. Additionally, the FERC order does not explicitly mention generation assets and is reasonably understood to focus on the most critical Transmission Facilities. The diagram below shows an example of a station.



Also, the SDT uses the phrase "Transmission stations or Transmission substations" to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (switching stations or switchyards). Therefore, the SDT chose to use both "station" and "substation" to refer to the locations where groups of Transmission Facilities exist.

On the issue of joint ownership, the SDT recognizes that this issue is not unique to CIP-014, and expects that the applicable Transmission Owners and Transmission Operators will develop memorandums of understanding, agreements, Coordinated Functional Registrations, or procedures, etc., to designate responsibilities under CIP-014 when joint ownership is at issue, which is similar to what many entities have completed for other Reliability Standards.

The language contained in the applicability section regarding the collector bus is directly copied from CIP-002-5.1, Attachment 1, and has no additional meaning within the CIP-014 standard.

Requirement R1

The initial risk assessment required under Requirement R1 must be completed on or before the effective date of the standard. Subsequent risk assessments are to be performed at least once every 30 or 60 months depending on the results of the previous risk assessment per Requirement R1, Part 1.1. In performing the risk assessment under Requirement R1, the

Transmission Owner should first identify their population of Transmission stations and Transmission substations that meet the criteria contained in Applicability Section 4.1.1. Requirement R1 then requires the Transmission Owner to perform a risk assessment, consisting of a transmission analysis, to determine which of those Transmission stations and Transmission Substations if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. The requirement is not to require identification of, and thus, not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

The standard does not mandate the specific analytical method for performing the risk assessment. The Transmission Owner has the discretion to choose the specific method that best suites its needs. As an example, an entity may perform a Power Flow analysis and stability analysis at a variety of load levels.

Performing Risk Assessments

The Transmission Owner has the discretion to select a transmission analysis method that fits its facts and system circumstances. To mandate a specific approach is not technically desirable and may lead to results that fail to adequately consider regional, topological, and system circumstances. The following guidance is only an example on how a Transmission Owner may perform a power flow and/or stability analysis to identify those Transmission stations and Transmission substations that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. An entity could remove all lines, without regard to the voltage level, to a single Transmission station or Transmission substation and review the simulation results to assess system behavior to determine if Cascading of Transmission Facilities, uncontrolled separation, or voltage or frequency instability is likely to occur over a significant area of the Interconnection. Using engineering judgment, the Transmission Owner (possibly in consultation with regional planning or operation committees and/or ISO/RTO committee input) should develop criteria (e.g. imposing a fault near the removed Transmission station or Transmission substation) to identify a contingency or parameters that result in potential instability, uncontrolled separation, or Cascading within an Interconnection. Regional consultation on these matters is likely to be

helpful and informative, given that the inputs for the risk assessment and the attributes of what constitutes instability, uncontrolled separation, or Cascading within an Interconnection will likely vary from region-to-region or from ISO-to-ISO based on topology, system characteristics, and system configurations. Criteria could also include post-contingency facilities loadings above a certain emergency rating or failure of a power flow case to converge. Available special protection systems (SPS), if any, could be applied to determine if the system experiences any additional instability which may result in uncontrolled separation. Example criteria may include:

(a) Thermal overloads beyond facility emergency ratings;

(b) Voltage deviation exceeding ± 10%; or

(c) Cascading outage/voltage collapse; or

(d) Frequency below under-frequency load shed points

Periodicity

A Transmission Owner who identifies one or more Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection is required to conduct a risk assessment at least once every 30 months. This period ensures that the risk assessment remains current with projected conditions and configurations in the planned system. This risk assessment, as the initial assessment, must consider applicable planned Transmission stations and Transmission substations to be in service within 24 months. The 30 month timeframe aligns with the 24 month planned to be in service date because the Transmission Owner is provided the flexibility, depending on its planning cycle and the frequency in which it may plan to construct a new Transmission station or Transmission substation to more closely align these dates. The requirement is to conduct the risk assessment at least once every 30 months, so for a Transmission Owner that believes it is better to conduct a risk assessment once every 24 months, because of its planning cycle, it has the flexibility to do so.

Transmission Owners that have not identified any Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection are unlikely to see changes to their risk assessment in the Near-Term Planning Horizon. Consequently, a 60 month periodicity for completing a subsequent risk assessment is specified.

Identification of Primary Control Centers

After completing the risk assessment specified in Requirement R1, it is important to additionally identify the primary control center that operationally controls each Transmission station or Transmission substation that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. A primary control center

"operationally controls" a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker.

Requirement R2

This requirement specifies verification of the risk assessment performed under Requirement R1 by an entity other than the owner or operator of the Requirement R1 risk assessment.

A verification of the risk assessment by an unaffiliated third party, as specified in Requirement R2, could consist of:

1. Certifying that the Requirement R1 risk assessment considers the Transmission stations and Transmission substations identified in Applicability Section 4.1.1.
2. Review of the model used to conduct the risk assessment to ensure it contains sufficient system topology to identify Transmission stations and Transmission substations that if rendered inoperable or damaged could cause instability, uncontrolled separation, or Cascading within an Interconnection.
3. Review of the Requirement R1 risk assessment methodology.

This requirement provides the flexibility for a Transmission Owner to select from unaffiliated registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term unaffiliated means that the selected verifying entity cannot be a corporate affiliate (*i.e.,* the verifying or third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit.

The prohibition on registered entities using a corporate affiliate to conduct the verification, however, does not prohibit a governmental entity (e.g., a city, a municipality, a U.S. federal power marketing agency, or any other political subdivision of U.S. or Canadian federal, state, or provincial governments) from selecting as the verifying entity another governmental entity within the same political subdivision. For instance, a U.S. federal power marketing agency may select as its verifier another U.S. federal agency to conduct its verification so long as the selected entity has transmission planning or analysis experience. Similarly, a Transmission Owner owned by a Canadian province can use a separate agency of that province to perform the verification. The verifying entity, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

Requirement R2 also provides that the "verification may occur concurrent with or after the risk assessment performed under Requirement R1." This provision is designed to provide the Transmission Owner the flexibility to work with the verifying entity throughout (*i.e.,* concurrent with) the risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could collaborate with their unaffiliated verifying entity to perform the risk assessment under Requirement R1 such that both Requirement R1 and Requirement R2 are satisfied concurrently. The intent of Requirement R2

is to have an entity other than the owner or operator of the facility to be involved in the risk assessment process and have an opportunity to provide input. Accordingly, Requirement R2 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the risk assessment and subsequently has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the risk assessment.

Characteristics to consider in selecting a third party reviewer could include:

- Registered Entity with applicable planning and reliability functions.
- Experience in power system studies and planning.
- The entity's understanding of the MOD standards, TPL standards, and facility ratings as they pertain to planning studies.
- The entity's familiarity with the Interconnection within which the Transmission Owner is located.

With respect to the requirement that Transmission owners develop and implement procedures for protecting confidential and sensitive information, the Transmission Owner could have a method for identifying documents that require confidential treatment. One mechanism for protecting confidential or sensitive information is to prohibit removal of sensitive or confidential information from the Transmission Owner's site. Transmission Owners could include such a prohibition in a non-disclosure agreement with the verifying entity.

A Technical feasibility study is not required in the Requirement R2 documentation of the technical basis for not modifying the identification in accordance with the recommendation.

On the issue of the difference between a verifier in Requirement R2 and a reviewer in Requirement R6, the SDT indicates that the verifier will confirm that the risk assessment was completed in accordance with Requirement R1, including the number of Transmission stations and substations identified, while the reviewer in Requirement R6 is providing expertise on the manner in which the evaluation of threats was conducted in accordance with Requirement R4, and the physical security plan in accordance with Requirement R5. In the latter situation there is no verification of a technical analysis, rather an application of experience and expertise to provide guidance or recommendations, if needed.

Parts 2.4 and 6.4 require the entities to have procedures to protect the confidentiality of sensitive or confidential information. Those procedures may include the following elements:

1. Control and retention of information on site for third party verifiers/reviewers.
2. Only "need to know" employees, etc., get the information.
3. Marking documents as confidential
4. Securely storing and destroying information when no longer needed.
5. Not releasing information outside the entity without, for example, General Counsel sign-off.

Requirement R3

Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first completing the risk assessment specified by Requirement R1 and the verification specified by Requirement R2. Requirement R3 is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1 receive notice so that the Transmission Operator may fulfill the rest of the obligations required in Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include within the notice the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or as a result of the verification process under Requirement R2.

Requirement R4

This requirement requires owners and operators of facilities identified by the Requirement R1 risk assessment and that are verified under Requirement R2 to conduct an assessment of potential threats and vulnerabilities to those Transmission stations, Transmission substations, and primary control centers using a tailored evaluation process. Threats and vulnerabilities may vary from facility to facility based on any number of factors that include, but are not limited to, location, size, function, existing physical security protections, and attractiveness as a target.

In order to effectively conduct a threat and vulnerability assessment, the asset owner may be the best source to determine specific site vulnerabilities, but current and evolving threats may best be determined by others in the intelligence or law enforcement communities. A number of resources have been identified in the standard, but many others exist and asset owners are not limited to where they may turn for assistance. Additional resources may include state or local fusion centers, U.S. Department of Homeland Security, Federal Bureau of Investigations (FBI), Public Safety Canada, Royal Canadian Mounted Police, and InfraGard chapters coordinated by the FBI.

The Responsible Entity is required to take a number of factors into account in Parts 4.1 to 4.3 in order to make a risk-based evaluation under Requirement R4.

To assist in determining the current threat for a facility, the prior history of attacks on similarly protected facilities should be considered when assessing probability and likelihood of occurrence at the facility in question.

Resources that may be useful in conducting threat and vulnerability assessments include:

- NERC Security Guideline for the Electricity Sector: Physical Security.
- NERC Security Guideline: Physical Security Response.
- ASIS International General Risk Assessment Guidelines.
- ASIS International Facilities Physical Security Measure Guideline.

- ASIS International Security Management Standard: Physical Asset Protection.
- Whole Building Design Guide - Threat/Vulnerability Assessments.

Requirement R5

This requirement specifies development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Requirement R5 specifies the following attributes for the physical security plan:

- *Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.*

  Resiliency may include, among other things:

  a. System topology changes,

  b. Spare equipment,

  c. Construction of a new Transmission station or Transmission substation.

  While most security measures will work together to collectively harden the entire site, some may be allocated to protect specific critical components. For example, if protection from gunfire is considered necessary, the entity may only install ballistic protection for critical components, not the entire site.

- *Law enforcement contact and coordination information.*

  Examples of such information may be posting 9-1-1 for emergency calls and providing substation safety and familiarization training for local and federal law enforcement, fire department, and Emergency Medical Services.

- *A timeline for executing the physical security enhancements and modifications specified in the physical security plan.*

  Entities have the flexibility to prioritize the implementation of the various resiliency or security enhancements and modifications in their security plan according to risk, resources, or other factors. The requirement to include a timeline in the physical security plan for executing the actual physical security enhancements and modifications does not also require that the enhancements and modifications be completed within 120 days. The actual timeline may extend beyond the 120 days, depending on the amount of work to be completed.

- *Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).*

  A registered entity's physical security plan should include processes and responsibilities for obtaining and handling alerts, intelligence, and threat warnings from various

sources. Some of these sources could include the ERO, ES-ISAC, and US and/or Canadian federal agencies. This information should be used to reevaluate or consider changes in the security plan and corresponding security measures of the security plan found in R5.

Incremental changes made to the physical security plan prior to the next required third party review do not require additional third party reviews.

Requirement R6

This requirement specifies review by an entity other than the Transmission Owner or Transmission Operator with appropriate expertise for the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5. As with Requirement R2, the term unaffiliated means that the selected third party reviewer cannot be a corporate affiliate (*i.e.,* the third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Operator). A third party reviewer also cannot be a division of the Transmission Operator that operates as a functional unit.

As noted in the guidance for Requirement R2, the prohibition on registered entities using a corporate affiliate to conduct the review, however, does not prohibit a governmental entity from selecting as the third party reviewer another governmental entity within the same political subdivision. For instance, a city or municipality may use its local enforcement agency, so long as the local law enforcement agency satisfies the criteria in Requirement R6. The third party reviewer, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

The Responsible Entity can select from several possible entities to perform the review:

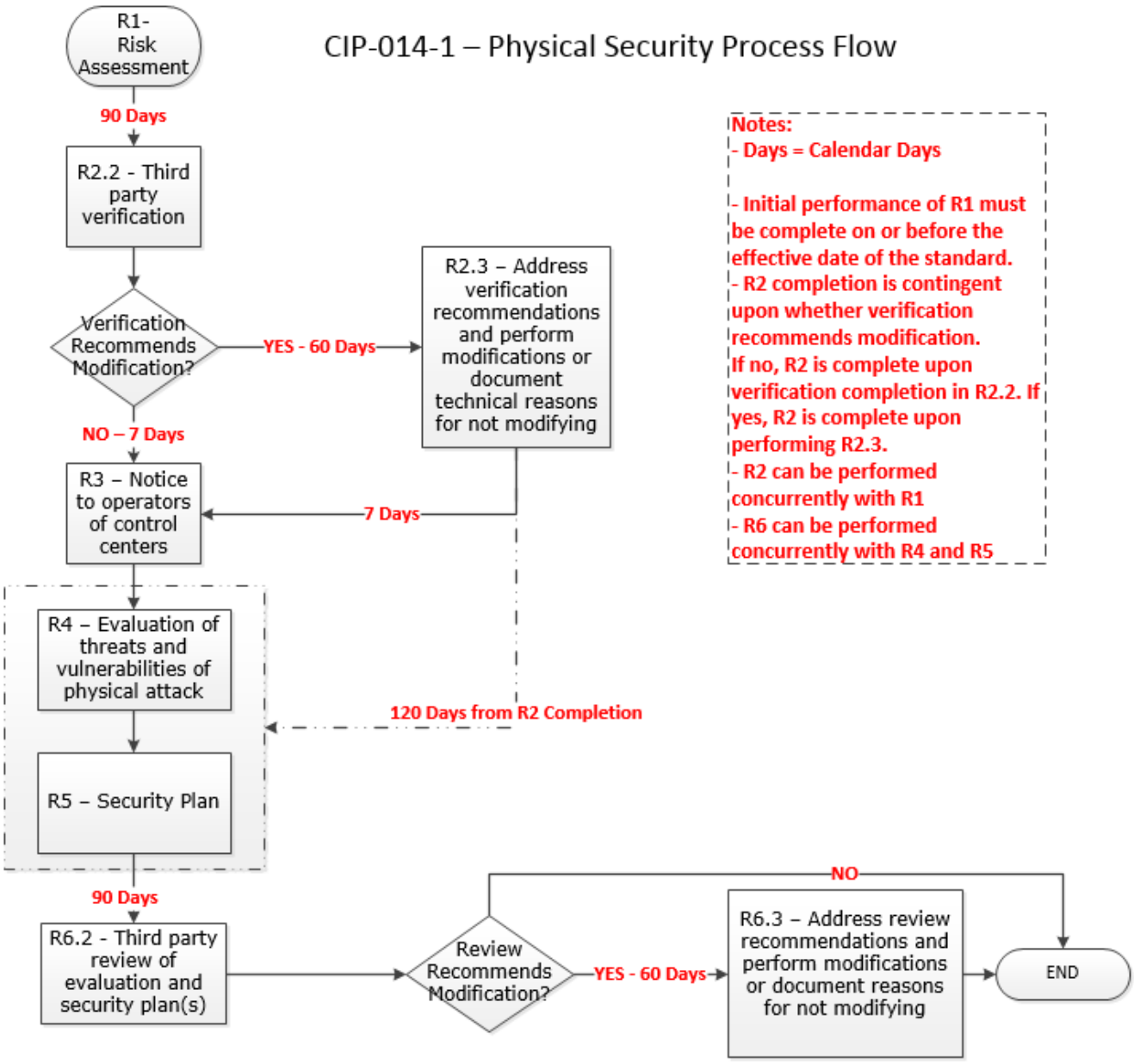
- *An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.*

  In selecting CPP and PSP for use in this standard, the SDT believed it was important that if a private entity such as a consulting or security firm was engaged to conduct the third party review, they must tangibly demonstrate competence to conduct the review. This includes electric industry physical security experience and either of the premier security industry certifications sponsored by ASIS International. The ASIS certification program was initiated in 1977, and those that hold the CPP certification are board certified in security management. Those that hold the PSP certification are board certified in physical security.

- *An entity or organization approved by the ERO.*
- *A governmental agency with physical security expertise.*
- *An entity or organization with demonstrated law enforcement, government, or military physical security expertise.*

As with the verification under Requirement R2, Requirement R6 provides that the "review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5." This provision is designed to provide applicable Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout (*i.e.,* concurrent with) the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5, which for some Responsible Entities may be more efficient and effective. In other words, a Transmission Owner or Transmission Operator could collaborate with their unaffiliated third party reviewer to perform an evaluation of potential threats and vulnerabilities (Requirement R4) and develop a security plan (Requirement R5) to satisfy Requirements R4 through R6 simultaneously. The intent of Requirement R6 is to have an entity other than the owner or operator of the facility to be involved in the Requirement R4 evaluation and the development of the Requirement R5 security plans and have an opportunity to provide input on the evaluation and the security plan. Accordingly, Requirement R6 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the evaluation and develops the security plan itself and then has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the evaluation and develop the security plan.

Timeline


CIP-014-1 – Physical Security Process Flow
R1- Risk Assessment
90 Days
R2.2 - Third party verification
Verification Recommends Modification?
YES - 60 Days
R2.3 – Address verification recommendations and perform modifications or document technical reasons for not modifying
NO – 7 Days
R3 – Notice to operators of control centers
7 Days
R4 – Evaluation of threats and vulnerabilities of physical attack
120 Days from R2 Completion
R5 – Security Plan
90 Days
R6.2 - Third party review of evaluation and security plan(s)
Review Recommends Modification?
YES - 60 Days
NO
R6.3 – Address review recommendations and perform modifications or document reasons for not modifying
END
Notes:
- Days = Calendar Days
- Initial performance of R1 must be complete on or before the effective date of the standard.
- R2 completion is contingent upon whether verification recommends modification. If no, R2 is complete upon verification completion in R2.2. If yes, R2 is complete upon performing R2.3.
- R2 can be performed concurrently with R1
- R6 can be performed concurrently with R4 and R5

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. A revised SAR was approved by the Standards Committee on December 9, 2014 to address the directives issued in FERC Order No. 802 issued on November 20, 2014, in Docket No. RD14-15-000, *Physical Security Reliability Standard*, 146 FERC ¶ 61,140 (2014). The appointed Physical Security Standard Drafting Team made the revisions to the standard.

Description of Current Draft

This is the first draft of the proposed Reliability Standard, and it is being posted for a 45-day comment and concurrent initial ballot period. This draft includes proposed revisions to address the directives issued in FERC Order No. 802.

Anticipated Actions	Anticipated Date
45-day Comment and Initial Ballot.	February-March, 2015
10-day Final Ballot.	April, 2015
BOT Adoption.	May, 2015
File with applicable Regulatory Authorities.	June, 2015

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the NERC Glossary of Terms used in Reliability Standards (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None

A. Introduction

1. Title: Physical Security

2. Number: CIP-014-1

3. Purpose: To identify and protect Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection.

4. Applicability:

4.1. Functional Entities:

4.1.1 Transmission Owner that owns a Transmission station or Transmission substation that meets any of the following criteria:

4.1.1.1 Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

4.1.1.2 Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

4.1.1.3 Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or

Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

4.1.1.4 Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

4.1.2 Transmission Operator.

Exemption: Facilities in a "protected area," as defined in 10 C.F.R. § 73.2, within the scope of a security plan approved or accepted by the Nuclear Regulatory Commission are not subject to this Standard; or, Facilities within the scope of a security plan approved or accepted by the Canadian Nuclear Safety Commission are not subject to this Standard.

5. Effective Dates:

See Implementation Plan for CIP-014-2.~~CIP-014-1 is effective the first day of the first calendar quarter that is six months beyond the date that this standard is approved by applicable regulatory authorities, or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. In those jurisdictions where regulatory approval is not required, CIP-014-1 shall become effective on the first day of the first calendar quarter that is six months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

6. Background:

This Reliability Standard addresses the directives from the FERC order issued March 7, 2014, *Reliability Standards for Physical Security Measures*, 146 FERC ¶ 61,166 (2014), which required NERC to develop a physical security reliability standard(s) to identify and protect facilities that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection.

B. Requirements and Measures

R1. Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. *[VRF: High; Time-Horizon: Long-term Planning]*

1.1. Subsequent risk assessments shall be performed:

- At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection; or

- At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection.

1.2. The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.

M1. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the risk assessment of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria in Applicability Section 4.1.1 as specified in Requirement R1. Additionally, examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the identification of the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment as specified in Requirement R1, Part 1.2.

Rationale for Requirement R1:

This requirement meets the FERC directive from paragraph 6 of its~~in the~~ March 7, 2014 order on physical security to perform a risk assessment to identify which facilities if rendered inoperable or damaged could impact an Interconnection through ~~widespread~~ instability, uncontrolled separation, or cascading failures. The requirement is not to require identification of, and thus, not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

~~It~~ Requirement R1 also meets the ~~portion of the~~FERC directive ~~from paragraph 11~~ for periodic reevaluation of the risk assessment by requiring the risk assessment to be performed every 30 months (or 60 months for an entity that has not identified in a previous risk assessment ~~any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection~~).

After identifying each Transmission station and Transmission substation that meets the criteria in Requirement R1, it is important to additionally identify the primary control center that operationally controls that Transmission station or Transmission substation (*i.e.,* the control center whose electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker, compared to a control center that only has the ability to monitor the Transmission station and Transmission substation and, therefore, must coordinate direct physical action through another entity).

R2. Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with or after the risk assessment performed under Requirement R1. *[VRF: Medium; Time-Horizon: Long-term Planning]*

2.1. Each Transmission Owner shall select an unaffiliated verifying entity that is either:

- A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or
- An entity that has transmission planning or analysis experience.

2.2. The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90 calendar days following the completion of the Requirement R1 risk assessment.

2.3. If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation:

- Modify its identification under Requirement R1 consistent with the recommendation; or
- Document the technical basis for not modifying the identification in accordance with the recommendation.

2.4. Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M2. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner completed an unaffiliated third party verification of the Requirement R1 risk assessment and satisfied all of the applicable provisions of Requirement R2, including, if applicable, documenting the technical basis for not modifying the Requirement R1 identification as specified under Part 2.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 2.4.

Rationale for Requirement R2:

This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring verification by an entity other than the owner or operator of the risk assessment performed under Requirement R1.

This requirement provides the flexibility for a Transmission Owner to select registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term "unaffiliated" means that the selected verifying entity cannot be a corporate affiliate (*i.e.*, the verifying entity cannot be an entity that controls, is controlled by, or is under common control with, the Transmission owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit. The term "unaffiliated" is not intended to prohibit a governmental entity from using another government entity to be a verifier under Requirement R2.

Requirement R2 also provides the Transmission Owner the flexibility to work with the verifying entity throughout the Requirement R1 risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could coordinate with their unaffiliated verifying entity to perform a Requirement R1 risk assessment to satisfy both Requirement R1 and Requirement R2 concurrently.

Planning Coordinator is a functional entity listed in Part 2.1. The Planning Coordinator and Planning Authority are the same entity as shown in the NERC Glossary of Terms Used in NERC Reliability Standards.

R3. For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the primary control center of such identification and the date of completion of Requirement R2. *[VRF: Lower; Time-Horizon: Long-term Planning]*

3.1. If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.

M3. Examples of acceptable evidence may include, but are not limited to, dated written or electronic notifications or communications that the Transmission Owner notified each Transmission Operator, as applicable, according to Requirement R3.

Rationale for Requirement R3:

Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first identifying which Transmission stations and Transmission substations meet the criteria specified by Requirement R1, as verified according to Requirement R2. This requirement is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1, Part 1.2 of a Transmission station or Transmission substation verified according to Requirement R2 receives notice of such identification so that the Transmission Operator may timely fulfill its resulting obligations under Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include notice of the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or the verification process under Requirement R2.

R4. Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following: *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]*

4.1. Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s);

4.2. Prior history of attack on similar facilities taking into account the frequency, geographic proximity, and severity of past physical security related events; and

4.3. Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.

M4. Examples of evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner or Transmission Operator conducted an evaluation of the potential threats and vulnerabilities of a physical attack to their respective Transmission station(s), Transmission substation(s) and primary control center(s) as specified in Requirement R4.

Rationale for Requirement R4:

This requirement meets the FERC directive from paragraph 8 in the order on physical security that the reliability standard must require tailored evaluation of potential threats and vulnerabilities to facilities identified in Requirement R1 and verified according to Requirement R2. Threats and vulnerabilities may vary from facility to facility based on factors such as the facility's location, size, function, existing protections, and attractiveness of the target. As such, the requirement does not mandate a one-size-fits-all approach but requires entities to account for the unique characteristics of their facilities.

Requirement R4 does not explicitly state when the evaluation of threats and vulnerabilities must occur or be completed. However, Requirement R5 requires that the entity's security plan(s), which is dependent on the Requirement R4 evaluation, must be completed within 120 calendar days following completion of Requirement R2. Thus, an entity has the flexibility when to complete the Requirement R4 evaluation, provided that it is completed in time to comply with the requirement in Requirement R5 to develop a physical security plan 120 calendar days following completion of Requirement R2.

R5. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s). The physical security plan(s) shall be developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: *[VRF: High; Time-Horizon: Long-term Planning]*

5.1. Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.

5.2. Law enforcement contact and coordination information.

5.3. A timeline for executing the physical security enhancements and modifications specified in the physical security plan.

5.4. Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).

M5. Examples of evidence may include, but are not limited to, dated written or electronic documentation of its physical security plan(s) that covers their respective identified

and verified Transmission station(s), Transmission substation(s), and primary control center(s) as specified in Requirement R5, and additional evidence demonstrating execution of the physical security plan according to the timeline specified in the physical security plan.

Rationale for Requirement R5:

This requirement meets the FERC directive from paragraph 9 in the order on physical security requiring the development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

R6. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5. *[VRF: Medium; Time-Horizon: Long-term Planning]*

6.1. Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following:

- An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.
- An entity or organization approved by the ERO.
- A governmental agency with physical security expertise.
- An entity or organization with demonstrated law enforcement, government, or military physical security expertise.

6.2. The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5.

6.3. If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:

- Modify its evaluation or security plan(s) consistent with the recommendation; or
- Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation.

6.4. Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M6. Examples of evidence may include, but are not limited to, written or electronic documentation that the Transmission Owner or Transmission Operator had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 as specified in Requirement R6 including, if applicable, documenting the reasons for not modifying the evaluation or security plan(s) in accordance with a recommendation under Part 6.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 6.4.

Rationale for Requirement R6:

This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring review by an entity other than the owner or operator with appropriate expertise of the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5.

As with the verification required by Requirement R2, Requirement R6 provides Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout the Requirement R4 evaluation and the development of the Requirement R5 security plan(s). This would allow entities to satisfy their obligations under Requirement R6 concurrent with the satisfaction of their obligations under Requirements R4 and R5.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence during an on-site visit to show that it was compliant for the full time period since the last audit.

The Transmission Owner and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation.

The responsible entities shall retain documentation as evidence for three years.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records, subject to the confidentiality provisions of Section 1500 of the Rules of Procedure and the provisions of Section 1.4 below.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

Confidentiality: To protect the confidentiality and sensitive nature of the evidence for demonstrating compliance with this standard, all evidence will be retained at the Transmission Owner's and Transmission Operator's facilities.

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**High**	The Transmission Owner performed an initial risk assessment but did so after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to two calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~	The Transmission Owner performed an initial risk assessment but did so more than two calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to four calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could	The Transmission Owner performed an initial risk assessment but did so more than four calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to six calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~	The Transmission Owner performed an initial risk assessment but did so more than six calendar months after the date specified in the implementation plan for performing the initial risk assessment; OR The Transmission Owner failed to perform an initial risk assessment; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 30 calendar months but less than or equal to 32 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an	result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 32 calendar months but less than or equal to 34 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an	instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 34 calendar months but less than or equal to 36 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection	Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability,

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Interconnection performed a subsequent risk assessment but did so after 60 calendar months but less than or equal to 62 calendar months.	Interconnection performed a subsequent risk assessment but did so after 62 calendar months but less than or equal to 64 calendar months.	performed a subsequent risk assessment but did so after 64 calendar months but less than or equal to 66 calendar months; OR The Transmission Owner performed a risk assessment but failed to include Part 1.2.	uncontrolled separation, or Cascading within an Interconnection failed to perform a risk assessment; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 66 calendar months;

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Transmission Owner that has not identified in its previous risk assessment any Transmission station and Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a subsequent risk assessment.
R2	**Long-term Planning**	**Medium**	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so in more than 90 calendar days but	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 100 calendar days but	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 110 calendar days but less than or equal to	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 120 calendar days

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			less than or equal to 100 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 60 calendar days and less than or equal to 70 calendar days from completion of the third party verification.	less than or equal to 110 calendar days following completion of Requirement R1; Or The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 70 calendar days and less than or equal to 80 calendar days from completion of the third party verification.	120 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 80 calendar days from completion of the third party verification; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed	following completion of Requirement R1; OR The Transmission Owner failed to have an unaffiliated third party verify the risk assessment performed under Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to implement procedures for protecting information per Part 2.4.

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					under Requirement R1 but failed to modify or document the technical basis for not modifying its identification under R1 as required by Part 2.3.	
R3	**Long-term Planning**	**Lower**	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than seven calendar days and less than or equal to nine calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than nine calendar days and less than or equal to 11 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 11 calendar days and less than or equal to 13 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 13 calendar days following the completion of Requirement R2; OR The Transmission Owner failed to notify the Transmission Operator that it operates a control

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			operates the primary control center of the removal from the identification in Requirement R1 but did so more than seven calendar days and less than or equal to nine calendar days following the verification or the subsequent risk assessment.	operates the primary control center of the removal from the identification in Requirement R1 but did so more than nine calendar days and less than or equal to 11 calendar days following the verification or the subsequent risk assessment.	of the removal from the identification in Requirement R1 but did so more than 11 calendar days and less than or equal to 13 calendar days following the verification or the subsequent risk assessment.	center identified in Requirement R1; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 13 calendar days following the verification or the subsequent risk assessment. OR The Transmission Owner failed to notify the Transmission Operator that operates the primary control center of the removal from the

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						identification in Requirement R1.
R4	**Operations Planning, Long-term Planning**	**Medium**	N/A	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider one of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider two of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity failed to conduct an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1; OR The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						substation(s), and primary control center(s) identified in Requirement R1 but failed to consider Parts 4.1 through 4.3.
R5	**Long-term Planning**	**High**	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 120 calendar days but less than or equal to 130 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 130 calendar days but less than or equal to 140 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 140 calendar days but less than or equal to 150 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 150 calendar days after completing the verification in Requirement R2; OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include one of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include two of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include three of Parts 5.1 through 5.4 in the plan.	The Responsible Entity failed to develop and implement a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						center(s) identified in Requirement R1 and verified according to Requirement 2 but failed to include Parts 5.1 through 5.4 in the plan.
R6	**Long-term Planning**	**Medium**	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 90 calendar days but less than or equal to 100 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 100 calendar days but less than or equal to 110 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so more than 110 calendar days but less than or equal to 120 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed	The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 in more than 120 calendar days; OR The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 60 calendar days and less than or equal to 70 calendar days following completion of the third party review.	under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 70 calendar days and less than or equal to 80 calendar days following completion of the third party review.	under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 80 calendar days following completion of the third party review; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did not document the reason for not modifying the security plan(s) as specified in Part 6.3.	the security plan(s) developed under Requirement R5; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but failed to implement procedures for protecting information per Part 6.3.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Section 4 Applicability

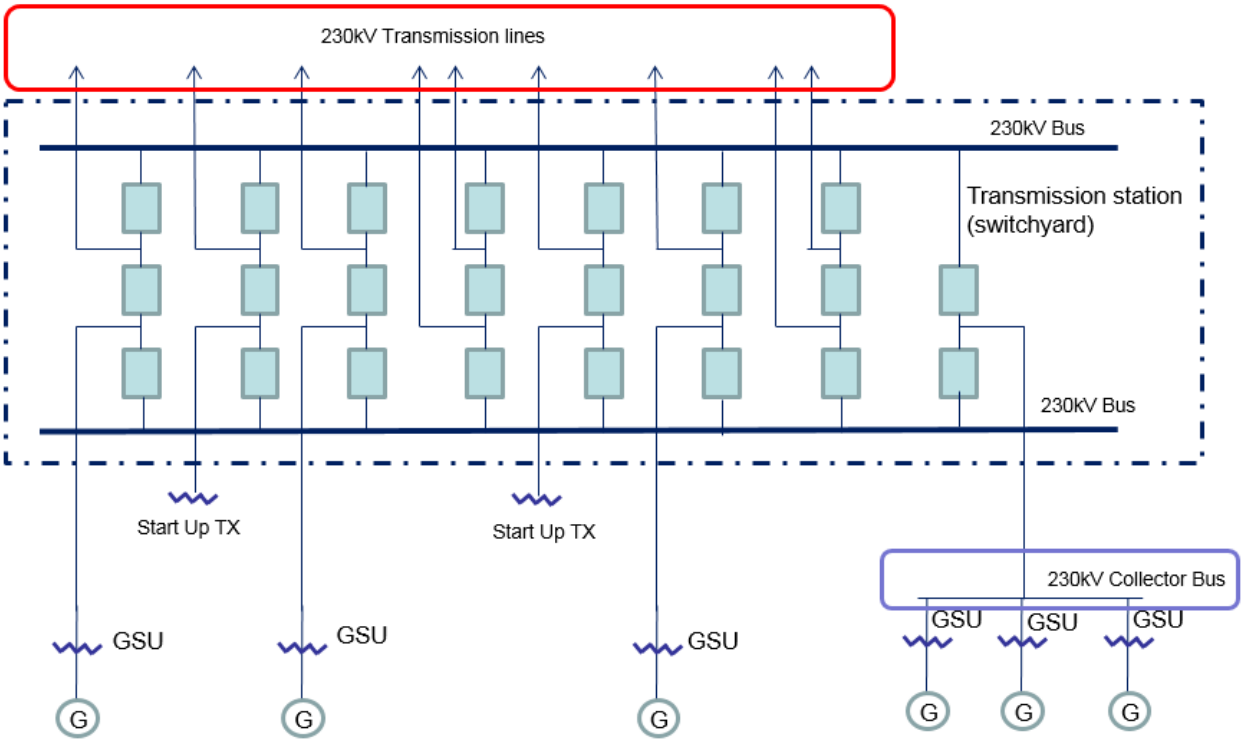
The purpose of Reliability Standard CIP-014~~-1~~ is to protect Transmission stations and Transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. To properly include those entities that own or operate such Facilities, the Reliability Standard CIP-014~~-1~~ first applies to Transmission Owners that own Transmission Facilities that meet the specific criteria in Applicability Section 4.1.1.1 through 4.1.1.4. The Facilities described in Applicability Section 4.1.1.1 through 4.1.1.4 mirror those Transmission Facilities that meet the bright line criteria for "Medium Impact" Transmission Facilities under Attachment 1 of Reliability Standard CIP-002-5.1. Each Transmission Owner that owns Transmission Facilities that meet the criteria in Section 4.1.1.1 through 4.1.1.4 is required to perform a risk assessment as specified in Requirement R1 to identify its Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. The Standard Drafting Team (SDT) expects this population will be small and that many Transmission Owners that meet the applicability of this standard will not actually identify any such Facilities. Only those Transmission Owners with Transmission stations or Transmission substations identified in the risk assessment (and verified under Requirement R2) have performance obligations under Requirements R3 through R6.

This standard also applies to Transmission Operators. A Transmission Operator's obligations under the standard, however, are only triggered if the Transmission Operator is notified by an applicable Transmission Owner under Requirement R3 that the Transmission Operator operates a primary control center that operationally controls a Transmission station(s) or Transmission substation(s) identified in the Requirement R1 risk assessment. A primary control center operationally controls a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical action at the identified Transmission station or Transmission substation, such as opening a breaker, as opposed to a control center that only has information from the Transmission station or Transmission substation and must coordinate direct action through another entity. Only Transmission Operators who are notified that they have primary control centers under this standard have performance obligations under Requirements R4 through R6. In other words, primary control center for purposes of this Standard is the control center that the Transmission Owner or Transmission Operator, respectively, uses as its primary, permanently-manned site to physically operate a Transmission station or Transmission substation that is identified in Requirement R1 and verified in Requirement R2. Control centers that provide back-up capability are not applicable, as they are a form of resiliency and intentionally redundant.

The SDT considered several options for bright line criteria that could be used to determine applicability and provide an initial threshold that defines the set of Transmission stations and Transmission substations that would meet the directives of the FERC order on physical security (*i.e.*, those that could cause ~~widespread~~ instability, uncontrolled separation, or Cascading within

an Interconnection). The SDT determined that using the criteria for Medium Impact Transmission Facilities in Attachment 1 of CIP-002-5.1 would provide a conservative threshold for defining which Transmission stations and Transmission substations must be included in the risk assessment in Requirement R1 of CIP-014~~-1~~. Additionally, the SDT concluded that using the CIP-002-5.1 Medium Impact criteria was appropriate because it has been approved by stakeholders, NERC, and FERC, and its use provides a technically sound basis to determine which Transmission Owners should conduct the risk assessment. As described in CIP-002-5.1, the failure of a Transmission station or Transmission substation that meets the Medium Impact criteria could have the capability to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). The SDT understands that using this bright line criteria to determine applicability may require some Transmission Owners to perform risk assessments under Requirement R1 that will result in a finding that none of their Transmission stations or Transmission substations would pose a risk of ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. However, the SDT determined that higher bright lines could not be technically justified to ensure inclusion of all Transmission stations and Transmission substations, and their associated primary control centers that, if rendered inoperable or damaged as a result of a physical attack could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. Further guidance and technical basis for the bright line criteria for Medium Impact Facilities can be found in the Guidelines and Technical Basis section of CIP-002-5.1.

Additionally, the SDT determined that it was not necessary to include Generator Operators and Generator Owners in the Reliability Standard. First, Transmission stations or Transmission substations interconnecting generation facilities are considered when determining applicability. Transmission Owners will consider those Transmission stations and Transmission substations that include a Transmission station on the high side of the Generator Step-up transformer (GSU) using Applicability Section 4.1.1.1 and 4.1.1.2. As an example, a Transmission station or Transmission substation identified as a Transmission Owner facility that interconnects generation will be subject to the Requirement R1 risk assessment if it operates at 500kV or greater or if it is connected at 200 kV – 499kV to three or more other Transmission stations or Transmission substations and has an "aggregate weighted value" exceeding 3000 according to the table in Applicability Section 4.1.1.2. Second, the Transmission analysis or analyses conducted under Requirement R1 should take into account the impact of the loss of generation connected to applicable Transmission stations or Transmission substations. Additionally, the FERC order does not explicitly mention generation assets and is reasonably understood to focus on the most critical Transmission Facilities. The diagram below shows an example of a station.



Also, the SDT uses the phrase "Transmission stations or Transmission substations" to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (switching stations or switchyards). Therefore, the SDT chose to use both "station" and "substation" to refer to the locations where groups of Transmission Facilities exist.

On the issue of joint ownership, the SDT recognizes that this issue is not unique to CIP-014~~-1~~, and expects that the applicable Transmission Owners and Transmission Operators will develop memorandums of understanding, agreements, Coordinated Functional Registrations, or procedures, etc., to designate responsibilities under CIP-014~~-1~~ when joint ownership is at issue, which is similar to what many entities have completed for other Reliability Standards.

The language contained in the applicability section regarding the collector bus is directly copied from CIP-002-5.1, Attachment 1, and has no additional meaning within the CIP-014~~-1~~ standard.

Requirement R1

The initial risk assessment required under Requirement R1 must be completed on or before the effective date of the standard. Subsequent risk assessments are to be performed at least once every 30 or 60 months depending on the results of the previous risk assessment per Requirement R1, Part 1.1. In performing the risk assessment under Requirement R1, the

Transmission Owner should first identify their population of Transmission stations and Transmission substations that meet the criteria contained in Applicability Section 4.1.1. Requirement R1 then requires the Transmission Owner to perform a risk assessment, consisting of a transmission analysis, to determine which of those Transmission stations and Transmission Substations if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. The requirement is not to require identification of, and thus, not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

The standard does not mandate the specific analytical method for performing the risk assessment. The Transmission Owner has the discretion to choose the specific method that best suites its needs. As an example, an entity may perform a Power Flow analysis and stability analysis at a variety of load levels.

Performing Risk Assessments

The Transmission Owner has the discretion to select a transmission analysis method that fits its facts and system circumstances. To mandate a specific approach is not technically desirable and may lead to results that fail to adequately consider regional, topological, and system circumstances. The following guidance is only an example on how a Transmission Owner may perform a power flow and/or stability analysis to identify those Transmission stations and Transmission substations that if rendered inoperable or damaged as a result of a physical attack could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. An entity could remove all lines, without regard to the voltage level, to a single Transmission station or Transmission substation and review the simulation results to assess system behavior to determine if Cascading of Transmission Facilities, uncontrolled separation, or voltage or frequency instability is likely to occur over a significant area of the Interconnection. Using engineering judgment, the Transmission Owner (possibly in consultation with regional planning or operation committees and/or ISO/RTO committee input) should develop criteria (e.g. imposing a fault near the removed Transmission station or Transmission substation) to identify a contingency or parameters that result in potential ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection. Regional

consultation on these matters is likely to be helpful and informative, given that the inputs for the risk assessment and the attributes of what constitutes ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection will likely vary from region-to-region or from ISO-to-ISO based on topology, system characteristics, and system configurations. ~~–~~Criteria could also include post-contingency facilities loadings above a certain emergency rating or failure of a power flow case to converge. Available special protection systems (SPS), if any, could be applied to determine if the system experiences any additional instability which may result in uncontrolled separation. Example criteria may include:

(a) Thermal overloads beyond facility emergency ratings;

(b) Voltage deviation exceeding ± 10%; or

(c) Cascading outage/voltage collapse; or

(d) Frequency below under-frequency load shed points

Periodicity

A Transmission Owner who identifies one or more Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection is required to conduct a risk assessment at least once every 30 months. This period ensures that the risk assessment remains current with projected conditions and configurations in the planned system. This risk assessment, as the initial assessment, must consider applicable planned Transmission stations and Transmission substations to be in service within 24 months. The 30 month timeframe aligns with the 24 month planned to be in service date because the Transmission Owner is provided the flexibility, depending on its planning cycle and the frequency in which it may plan to construct a new Transmission station or Transmission substation to more closely align these dates. The requirement is to conduct the risk assessment at least once every 30 months, so for a Transmission Owner that believes it is better to conduct a risk assessment once every 24 months, because of its planning cycle, it has the flexibility to do so.

Transmission Owners that have not identified any Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection are unlikely to see changes to their risk assessment in the Near-Term Planning Horizon. Consequently, a 60 month periodicity for completing a subsequent risk assessment is specified.

Identification of Primary Control Centers

After completing the risk assessment specified in Requirement R1, it is important to additionally identify the primary control center that operationally controls each Transmission station or Transmission substation that if rendered inoperable or damaged could result in ~~widespread~~

instability, uncontrolled separation, or Cascading within an Interconnection. A primary control center "operationally controls" a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker.

Requirement R2

This requirement specifies verification of the risk assessment performed under Requirement R1 by an entity other than the owner or operator of the Requirement R1 risk assessment.

A verification of the risk assessment by an unaffiliated third party, as specified in Requirement R2, could consist of:

1. Certifying that the Requirement R1 risk assessment considers the Transmission stations and Transmission substations identified in Applicability Section 4.1.1.
2. Review of the model used to conduct the risk assessment to ensure it contains sufficient system topology to identify Transmission stations and Transmission substations that if rendered inoperable or damaged could cause ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection.
3. Review of the Requirement R1 risk assessment methodology.

This requirement provides the flexibility for a Transmission Owner to select from unaffiliated registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term unaffiliated means that the selected verifying entity cannot be a corporate affiliate (*i.e.,* the verifying or third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit.

The prohibition on registered entities using a corporate affiliate to conduct the verification, however, does not prohibit a governmental entity (e.g., a city, a municipality, a U.S. federal power marketing agency, or any other political subdivision of U.S. or Canadian federal, state, or provincial governments) from selecting as the verifying entity another governmental entity within the same political subdivision. For instance, a U.S. federal power marketing agency may select as its verifier another U.S. federal agency to conduct its verification so long as the selected entity has transmission planning or analysis experience. Similarly, a Transmission Owner owned by a Canadian province can use a separate agency of that province to perform the verification. The verifying entity, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

Requirement R2 also provides that the "verification may occur concurrent with or after the risk assessment performed under Requirement R1." This provision is designed to provide the Transmission Owner the flexibility to work with the verifying entity throughout (*i.e.,* concurrent with) the risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could collaborate with their unaffiliated verifying entity to perform the risk assessment under Requirement R1 such that both

Requirement R1 and Requirement R2 are satisfied concurrently. The intent of Requirement R2 is to have an entity other than the owner or operator of the facility to be involved in the risk assessment process and have an opportunity to provide input. Accordingly, Requirement R2 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the risk assessment and subsequently has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the risk assessment.

Characteristics to consider in selecting a third party reviewer could include:

- Registered Entity with applicable planning and reliability functions.
- Experience in power system studies and planning.
- The entity's understanding of the MOD standards, TPL standards, and facility ratings as they pertain to planning studies.
- The entity's familiarity with the Interconnection within which the Transmission Owner is located.

With respect to the requirement that Transmission owners develop and implement procedures for protecting confidential and sensitive information, the Transmission Owner could have a method for identifying documents that require confidential treatment. One mechanism for protecting confidential or sensitive information is to prohibit removal of sensitive or confidential information from the Transmission Owner's site. Transmission Owners could include such a prohibition in a non-disclosure agreement with the verifying entity.

A Technical feasibility study is not required in the Requirement R2 documentation of the technical basis for not modifying the identification in accordance with the recommendation.

On the issue of the difference between a verifier in Requirement R2 and a reviewer in Requirement R6, the SDT indicates that the verifier will confirm that the risk assessment was completed in accordance with Requirement R1, including the number of Transmission stations and substations identified, while the reviewer in Requirement R6 is providing expertise on the manner in which the evaluation of threats was conducted in accordance with Requirement R4, and the physical security plan in accordance with Requirement R5. In the latter situation there is no verification of a technical analysis, rather an application of experience and expertise to provide guidance or recommendations, if needed.

Parts 2.4 and 6.4 require the entities to have procedures to protect the confidentiality of sensitive or confidential information. Those procedures may include the following elements:

1. Control and retention of information on site for third party verifiers/reviewers.
2. Only "need to know" employees, etc., get the information.
3. Marking documents as confidential
4. Securely storing and destroying information when no longer needed.
5. Not releasing information outside the entity without, for example, General Counsel sign-off.

Requirement R3

Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first completing the risk assessment specified by Requirement R1 and the verification specified by Requirement R2. Requirement R3 is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1 receive notice so that the Transmission Operator may fulfill the rest of the obligations required in Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include within the notice the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or as a result of the verification process under Requirement R2.

Requirement R4

This requirement requires owners and operators of facilities identified by the Requirement R1 risk assessment and that are verified under Requirement R2 to conduct an assessment of potential threats and vulnerabilities to those Transmission stations, Transmission substations, and primary control centers using a tailored evaluation process. Threats and vulnerabilities may vary from facility to facility based on any number of factors that include, but are not limited to, location, size, function, existing physical security protections, and attractiveness as a target.

In order to effectively conduct a threat and vulnerability assessment, the asset owner may be the best source to determine specific site vulnerabilities, but current and evolving threats may best be determined by others in the intelligence or law enforcement communities. A number of resources have been identified in the standard, but many others exist and asset owners are not limited to where they may turn for assistance. Additional resources may include state or local fusion centers, U.S. Department of Homeland Security, Federal Bureau of Investigations (FBI), Public Safety Canada, Royal Canadian Mounted Police, and InfraGard chapters coordinated by the FBI.

The Responsible Entity is required to take a number of factors into account in Parts 4.1 to 4.3 in order to make a risk-based evaluation under Requirement R4.

To assist in determining the current threat for a facility, the prior history of attacks on similarly protected facilities should be considered when assessing probability and likelihood of occurrence at the facility in question.

Resources that may be useful in conducting threat and vulnerability assessments include:

- NERC Security Guideline for the Electricity Sector: Physical Security.
- NERC Security Guideline: Physical Security Response.
- ASIS International General Risk Assessment Guidelines.

- ASIS International Facilities Physical Security Measure Guideline.
- ASIS International Security Management Standard: Physical Asset Protection.
- Whole Building Design Guide - Threat/Vulnerability Assessments.

Requirement R5

This requirement specifies development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Requirement R5 specifies the following attributes for the physical security plan:

- *Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.*

  Resiliency may include, among other things:

  a. System topology changes,

  b. Spare equipment,

  c. Construction of a new Transmission station or Transmission substation.

  While most security measures will work together to collectively harden the entire site, some may be allocated to protect specific critical components. For example, if protection from gunfire is considered necessary, the entity may only install ballistic protection for critical components, not the entire site.

- *Law enforcement contact and coordination information.*

  Examples of such information may be posting 9-1-1 for emergency calls and providing substation safety and familiarization training for local and federal law enforcement, fire department, and Emergency Medical Services.

- *A timeline for executing the physical security enhancements and modifications specified in the physical security plan.*

  Entities have the flexibility to prioritize the implementation of the various resiliency or security enhancements and modifications in their security plan according to risk, resources, or other factors. The requirement to include a timeline in the physical security plan for executing the actual physical security enhancements and modifications does not also require that the enhancements and modifications be completed within 120 days. The actual timeline may extend beyond the 120 days, depending on the amount of work to be completed.

- *Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).*

A registered entity's physical security plan should include processes and responsibilities for obtaining and handling alerts, intelligence, and threat warnings from various sources. Some of these sources could include the ERO, ES-ISAC, and US and/or Canadian federal agencies. This information should be used to reevaluate or consider changes in the security plan and corresponding security measures of the security plan found in R5.

Incremental changes made to the physical security plan prior to the next required third party review do not require additional third party reviews.

Requirement R6

This requirement specifies review by an entity other than the Transmission Owner or Transmission Operator with appropriate expertise for the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5. As with Requirement R2, the term unaffiliated means that the selected third party reviewer cannot be a corporate affiliate (*i.e.,* the third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Operator). A third party reviewer also cannot be a division of the Transmission Operator that operates as a functional unit.

As noted in the guidance for Requirement R2, the prohibition on registered entities using a corporate affiliate to conduct the review, however, does not prohibit a governmental entity from selecting as the third party reviewer another governmental entity within the same political subdivision. For instance, a city or municipality may use its local enforcement agency, so long as the local law enforcement agency satisfies the criteria in Requirement R6. The third party reviewer, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

The Responsible Entity can select from several possible entities to perform the review:

- *An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.*

  In selecting CPP and PSP for use in this standard, the SDT believed it was important that if a private entity such as a consulting or security firm was engaged to conduct the third party review, they must tangibly demonstrate competence to conduct the review. This includes electric industry physical security experience and either of the premier security industry certifications sponsored by ASIS International. The ASIS certification program was initiated in 1977, and those that hold the CPP certification are board certified in security management. Those that hold the PSP certification are board certified in physical security.

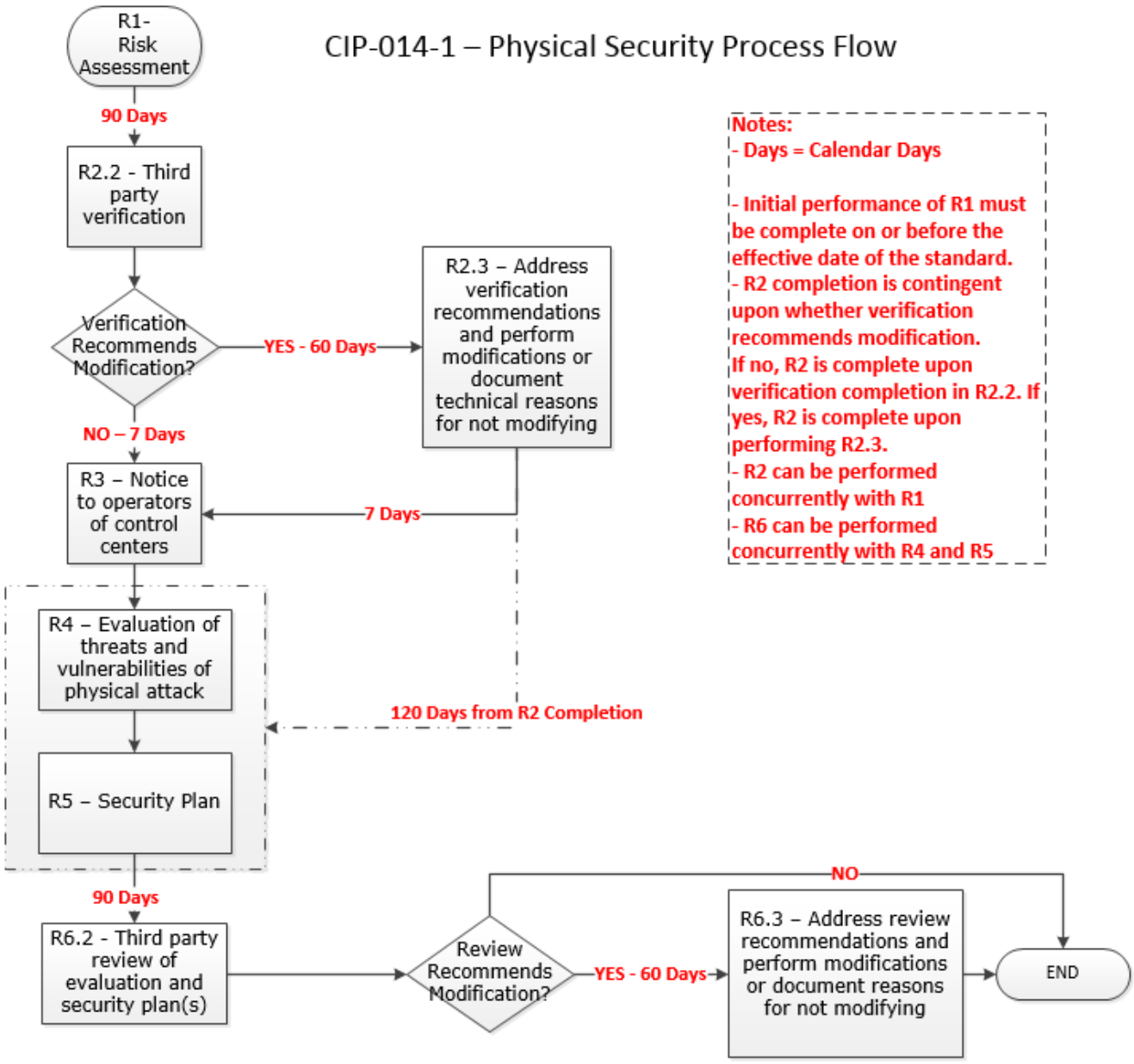
- *An entity or organization approved by the ERO.*

- *A governmental agency with physical security expertise.*

- *An entity or organization with demonstrated law enforcement, government, or military physical security expertise.*

As with the verification under Requirement R2, Requirement R6 provides that the "review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5." This provision is designed to provide applicable Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout (*i.e.,* concurrent with) the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5, which for some Responsible Entities may be more efficient and effective. In other words, a Transmission Owner or Transmission Operator could collaborate with their unaffiliated third party reviewer to perform an evaluation of potential threats and vulnerabilities (Requirement R4) and develop a security plan (Requirement R5) to satisfy Requirements R4 through R6 simultaneously. The intent of Requirement R6 is to have an entity other than the owner or operator of the facility to be involved in the Requirement R4 evaluation and the development of the Requirement R5 security plans and have an opportunity to provide input on the evaluation and the security plan. Accordingly, Requirement R6 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the evaluation and develops the security plan itself and then has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the evaluation and develop the security plan.

Timeline


CIP-014-1 – Physical Security Process Flow
R1- Risk Assessment
90 Days
R2.2 - Third party verification
Verification Recommends Modification?
YES - 60 Days
R2.3 – Address verification recommendations and perform modifications or document technical reasons for not modifying
NO – 7 Days
R3 – Notice to operators of control centers
7 Days
R4 – Evaluation of threats and vulnerabilities of physical attack
120 Days from R2 Completion
R5 – Security Plan
90 Days
R6.2 - Third party review of evaluation and security plan(s)
Review Recommends Modification?
YES - 60 Days
R6.3 – Address review recommendations and perform modifications or document reasons for not modifying
NO
END
Notes:
- Days = Calendar Days
- Initial performance of R1 must be complete on or before the effective date of the standard.
- R2 completion is contingent upon whether verification recommends modification. If no, R2 is complete upon verification completion in R2.2. If yes, R2 is complete upon performing R2.3.
- R2 can be performed concurrently with R1
- R6 can be performed concurrently with R4 and R5

DRAFT Reliability Standard Audit Worksheet[1]

CIP-014-2 – Physical Security

This section to be completed by the Compliance Enforcement Authority.

Audit ID:	Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity:	Registered name of entity being audited
NCR Number:	NCRnnnnn
Compliance Enforcement Authority:	Region or NERC performing audit
Compliance Assessment Date(s)[2]:	Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method:	[On-site Audit | Off-site Audit | Spot Check]
Names of Auditors:	Supplied by CEA

[1] NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The NERC RSAW language contained within this document provides a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserves the right to request additional evidence from the registered entity that is not included in this RSAW. Additionally, this RSAW includes excerpts from FERC Orders and other regulatory references. The FERC order cites are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC orders, and the language included in this document, FERC orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

Applicability of Requirements *[RSAW developer to insert correct applicability]*

	BA	DP	GO	GOP	IA	LSE	PA	PSE	RC	RP	RSG	TO	TOP	TP	TSP
R1												X[3,4]			
R2												X[3,4]			
R3												X[3,4]			
R4												X[3,4]	X[4]		
R5												X[3,4]	X[4]		
R6												X[3,4]	X[4]		

Legend:

Text with blue background:	Fixed text – do not edit
Text entry area with Green background:	Entity-supplied information
Text entry area with white background:	Auditor-supplied information

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[3] Applicability is further defined to owners of transmission Facilities operated at 500 kV or higher (see section 4.1.1.1 of the Standard) and owners of certain transmission Facilities operating between 200 kV and 499 kV where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations, per section 4.1.1.2 of the Standard. In addition, sections 4.1.1.3 and 4.1.1.4 bring additional transmission Facilities identified as either critical to the derivation of Interconnection Reliability Operating Limits and Nuclear Plant Interface, respectively, within the purview of the standard. Please see the referenced sections of the Standard for additional details regarding applicability of the Requirements to Transmission Owners.

[4] Facilities in a "protected area," as defined in 10 C.F.R. § 73.2, within the scope of a security plan approved or accepted by the Nuclear Regulatory Commission are not subject to this Standard; or, Facilities within the scope of a security plan approved or accepted by the Canadian Nuclear Safety Commission are not subject to this Standard.

Findings

(This section to be completed by the Compliance Enforcement Authority)

Req.	Finding	Summary and Documentation	Functions Monitored

Req.	Areas of Concern

Req.	Recommendations

Req.	Positive Observations

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Subject Matter Experts

Identify the Subject Matter Expert(s) responsible for this Reliability Standard.

Registered Entity Response (Required; Insert additional rows if needed):

SME Name	Title	Organization	Requirement(s)

Note to Auditors Concerning Third Party Verifications and Reviews

Requirements R2 and R6 prescribe, respectively, unaffiliated third party verifications for Requirement R1 and unaffiliated third party reviews for Requirements R4 and R5. Auditors are encouraged to rely on the verifications and reviews performed in cases where the verifying or reviewing entities are qualified, unaffiliated with the audited entity, and the scope of their verification or review is clear. The concept of reliance means using the work of others to avoid duplication of efforts and is consistent with recognized professional auditing standards, which are required for Compliance Audits per NERC's Rules of Procedure. Reliance in the context of this Reliability Standard means using the Requirement R2 verifications and Requirement R6 reviews to reduce audit risk and the related rigor of audit testing for Requirements R1, R4, and R5. However, in cases where the verifying or reviewing entity lacks the qualifications specified in Requirement R2 for verifications or Requirement R6 for reviewers, the required unaffiliation from the audited entity, or where the scope of the third party entity's verification or review is unclear, auditors may need to apply audit testing of Requirements R1, R4, or R5. For this reason, the Evidence Requested and Compliance Assessment Approach Sections are still present in this RSAW for Requirements R1, R4, and R5. We anticipate those sections will also facilitate expectations for entities and their unaffiliated third party verifiers and reviewers, assist Electric Reliability Organization (ERO) auditors to understand the audit procedures applied by unaffiliated third party verifiers and reviewers, and provide transparency between ERO auditors and Industry, should circumstances require audit testing of Requirements R1, R4, or R5. Further, it is an objective of the ERO to have transparent Evidence Requests and Compliance Assessment Approaches for every enforceable standard, whether they are in audit scope or not.

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R1 Supporting Evidence and Documentation

R1. Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1.The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that, if rendered inoperable or damaged, could result in instability, uncontrolled separation, or Cascading within an Interconnection.

1.1. Subsequent risk assessments shall be performed:

- At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2)one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection; or
- At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

1.2. The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.

M1. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the risk assessment of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria in Applicability Section 4.1.1 as specified in Requirement R1. Additionally, examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the identification of the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment as specified in Requirement R1, Part 1.2.

Registered Entity Response (Required):

Question: Do you own any Transmission stations/substations, either existing or planned in the next 24 months, meeting the applicability requirements of Section 4.1.1? ☐ Yes ☐ No

☐ This entity does not have any applicable Transmission stations/substations.

☐ Other: [Provide explanation below]

[Include additional information regarding the question here, including the type of response and format of the response requested, as appropriate.]

[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Compliance Narrative:

Provide a brief explanation of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
(R1) Provide the current and the immediately preceding dated risk assessments.
(R1) List of existing Transmission stations/substations that meet the criteria specified in Section 4.1.1.
(R1) List of Transmission stations/substations planned in the next 24 months that meet criteria specified in Section 4.1.1.
(R1 Part 1.2) List of primary control centers that operationally control each identified Transmission station/substation.

Registered Entity Evidence (Required):

The following information is required for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location of the evidence.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to CIP-014-1, R1

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R1) Review entity's process for determining Transmission stations/substations subject to identification in accordance with Requirement R1, including weighting described in Section 4.1.1.2.
	(R1) Review entity's risk assessment process to determine the Transmission stations/substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an interconnection.
	(R1) Ensure entity's risk assessment process includes Transmission stations/substations planned in the next 24 months.

	(R1) Ensure risk assessment(s) covers each Transmission station/substation meeting applicability described in Section 4.1.
	(R1 Part 1.1) If applicable, review any prior risk assessments and verify whether or not Transmission stations/substations were identified.
	(R1 Part 1.1) Review evidence that risk assessment was performed and verify that it occurred within the past 30 months where items were identified in the previous risk assessment and 60 months where no items were identified in the previous risk assessment.

Note to Auditor: Review entity's answer to the above Question and if the auditor can verify the answer is 'no,' Requirements R3-R6 do not apply and no further audit testing of Requirements R3-R6 is necessary, unless the entity performs the Transmission Operator function for a station/substation meeting the criteria of Requirement R1 Part 1.2.

The 24 month period referenced for Transmission stations/substations planned to be in service is as of the date of the risk assessment not the date of the audit.

See above Note Concerning Third Party Verifications for important details regarding audit risk assessment and related rigor of audit procedures to be applied for this Requirement.

Auditor Notes:

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R2 Supporting Evidence and Documentation

R2. Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with or after the risk assessment performed under Requirement R1.

2.1. Each Transmission Owner shall select an unaffiliated verifying entity that is either:

- A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator;
- An entity that has transmission planning or analysis experience.

2.2. The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90 calendar days following the completion of the Requirement R1 risk assessment.

2.3. If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a s Transmission station or Transmission substation::

- Modify its identification under Requirement R1 consistent with the recommendation; or
- Document the technical basis for not modifying the identification in accordance with the recommendation.

2.4. Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated verifying entity and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M2. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner completed an unaffiliated third verification of the Requirement R1 risk assessment and satisfied all of the applicable provisions of Requirement R2, including, if applicable, documenting the technical basis for not modifying the Requirement R1 identification as specified under Part 2.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 2.4.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
(R2) Dated evidence of third party verification of the entity's risk assessment performed under Requirement R1.
(R2 Part 2.1) Documented qualifications of the verifying party.
(R2 Part 2.3) Recommendations, if any, of the verifying party related to Requirement R1 risk assessments.
(R2 Part 2.3) Documentation of modifications and implementation of recommendations or technical basis for not implementing recommendations of the verifying party.
(R2 Part 2.4) Evidence that procedures were implemented to protect sensitive and confidential information.

Registered Entity Evidence (Required):

The following information is required for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location of the evidence.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to CIP-014-1, R2

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R2) Review evidence of third party verification of the entity's risk assessment and verify the following:
	(R2 Part 2.1) The reviewing entity is registered in accordance with Part 2.1 or has transmission planning or analysis experience.
	(R2 Part 2.2) Verification was completed within 90 calendar days of risk assessment.
	(R2 Part 2.3) Verifying entity's recommendations, if any, were used to modify the entity's Requirement R1 identification or the technical basis for not modifying the Requirement R1 identification is documented within 60 calendar days of completion of the verification.
	(R2 Part 2.4) Review non-disclosure agreement (or other evidence) to verify procedures for protecting sensitive or confidential information between the entity and third party were implemented.
Note to Auditor See Guidelines and Technical Basis section of the standard and Rationale for Requirement R2 associated with the Standard for additional details regarding the term 'unaffiliated.'	

The third party verification may occur concurrent with or after the risk assessment performed under Requirement R1.

Auditor Notes:

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R3 Supporting Evidence and Documentation

R3. For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner, the Transmission Owner shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the primary control center of such identification and the date of completion of Requirement R2.

3.1. If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.

M3. Examples of acceptable evidence may include, but are not limited to, dated written or electronic notifications or communications that the Transmission Owner notified each Transmission Operator, as applicable, according to Requirement R3.

Registered Entity Response (Required):

Question: Are there any primary control centers identified in Requirement R1, Part 1.2 that are not under operational control of your NERC registration? ☐ Yes ☐ No

[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Compliance Narrative:

Provide a brief explanation of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
(R3) If applicable, dated communications with Transmission Operators demonstrating notification and the date of completion of Requirement R2.

Registered Entity Evidence (Required):

The following information is required for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location of the evidence.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to CIP-014-1, R3

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R3) For each applicable primary control center identified in Requirement R1 Part 1.2 not under the control of the entity's registration, verify notification exists and contains the date of completion of Requirement R2.
	(R3 Part 3.1) For each Transmission station/substation removed under Part 3.1, ensure the responsible Transmission Operator was notified of the removal within seven calendar days of removal from identification.
Note to Auditor: Note the entity's response to the above Question. If auditor can verify the entity's answer of 'No,' then Requirement R3 is not applicable and no further audit testing is required.	

Auditor Notes:

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R4 Supporting Evidence and Documentation

R4. Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following:

4.1. Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s);

4.2. Prior history of attack on similar facilities taking into account the frequency, geographic proximity, and severity of past physical security related events; and

4.3. Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.

M4. Examples of evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner or Transmission Operator conducted an evaluation of the potential threats and vulnerabilities of a physical attack to their respective Transmission station(s), Transmission substation(s) and primary control center(s) as specified in Requirement R4.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
(R4) A description of the entity's process for executing the evaluation prescribed in Requirement R4.
(R4) Dated evidence of the evaluation prescribed in Requirement R4.

Registered Entity Evidence (Required):

The following information is required for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location of the evidence.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to CIP-014-1, R4

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R4) Review evidence of evaluation and verify it considers the following:
	(R4) Potential threats and vulnerabilities as described in Requirement R4.
	(R4 Part 4.1) Unique characteristics as described in Requirement R4 Part 4.1.
	(R4 Part 4.2) Prior history of attack on similar facilities taking into account the frequency, geographic proximity, and severity of past physical security related events.
	(R4 Part 4.3) Intelligence or warnings as described in Part 4.3.
Note to Auditor: See above Note Concerning Third Party Verifications for important details regarding audit risk assessment and related rigor of audit procedures to be applied for this Requirement. Auditor should cross reference the Transmission stations/substations and primary control centers identified in the risk assessment performed under Requirement R1 to the evaluation prescribed in Requirement R4 to ensure it is complete.	

Auditor Notes:

R5 Supporting Evidence and Documentation

R5. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center identified in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s). The physical security plan(s) shall be developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes:

5.1. Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.

5.2. Law enforcement contact and coordination information.

5.3. A timeline for executing the physical security enhancements and modifications specified in the physical security plan.

5.4. Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).

M5. Examples of evidence may include, but are not limited to, dated written or electronic documentation of its physical security plan(s) that covers their respective identified and verified Transmission station(s), Transmission substation(s), and primary control center(s) as specified in Requirement R5, and additional evidence demonstrating execution of the physical security plan according to the timeline specified in the physical security plan.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
(R5) Dated physical security plan(s).

Registered Entity Evidence (Required):

The following information is required for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location of the evidence.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to CIP-014-1, R5

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R5) Review evidence and verify the physical security plan(s) covers the Transmission stations/substations and primary controls identified in Requirements R1 and/or R2, and verify plan was developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). In addition, verify the plan includes the following attributes:
	(R5 Part 5.1) Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.
	(R5 Part 5.2) Law enforcement contact and coordination information.
	(R5 Part 5.3) A timeline for executing physical security enhancements and modifications specified in the physical security plan.
	(R5 Part 5.4) Provisions to evaluate evolving physical threats, and their corresponding security measures in accordance with R5 Part 5.4
	(R5) Verify implementation of physical security plan(s). See 'Note to Auditor' for details.
Note to Auditor: See above Note Concerning Third Party Verifications for important details regarding audit risk assessment and related rigor of audit procedures to be applied for this Requirement. Auditor should cross reference the Transmission stations/substations and primary control centers identified in the risk assessment performed under Requirement R1 to the evaluation prescribed in Requirement R4 and the security plan(s) prescribed in Requirement R5 to ensure the plan addresses vulnerabilities to	

physical attacks per the evaluation conducted in Requirement R4.

Requirement R5 includes implementation of the security plan(s), which is not within the scope of the third party review described in Requirement R6. Auditors can gain reasonable assurance security plan(s) was/were implemented by determining if specific actions prescribed by the plan(s) have taken place within the timelines established by the plan(s). For example, if the plan calls for certain procedures to occur, then auditors could ask for evidence demonstrating the procedure has been implemented within the timeline established in the security plan. Also, if the plan calls for construction of a barrier, an auditor could verify evidence that such a barrier was constructed in accordance with the entity's timeline. As auditors should obtain reasonable, not absolute, assurance the plan(s) was/were implemented, testing implementation on a sample basis may be appropriate.

Auditor Notes:

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R6 Supporting Evidence and Documentation

R6. Each Transmission Owner identifies a Transmission station, Transmission substation, or primary control center identified in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5

6.1. Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following:

- An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.
- An entity or organization approved by the ERO.
- A governmental agency with physical security expertise.
- An entity or organization with demonstrated law enforcement, government, or military physical security expertise.

6.2. The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5.

6.3. If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:

- Modify its security plan(s) consistent with the recommendation; or
- Document the reason for not modifying the security plan(s) consistent with the recommendation

6.4. Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated reviewing entity and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M6. Examples of evidence may include, but are not limited to, written or electronic documentation that the Transmission Owner or Transmission Operator had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 as specified in Requirement R6 including, if applicable, documenting the reasons for not modifying the evaluation or security

plan(s) in accordance with a recommendation under Part 6.3. Examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 6.4

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
(R6) Dated Evidence of unaffiliated third party review of entity's Requirement R4 evaluation and Requirement R5 security plan(s).
(R6 Part 6.1) Evidence that reviewing entity staff meets qualifications identified in Part 6.1.
(R6 Part 6.3) Recommendations of reviewing party related to Requirement R4 evaluation and Requirement R5 security plan.
(R6 Part 6.3) Dated documentation of modifications and implementation of recommendations or reasons and compensating mitigating measures for not implementing recommendations of the reviewing party.
(R6 Part 6.4) Evidence that procedures were implemented to protect sensitive and confidential information.

Registered Entity Evidence (Required):

The following information is required for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location of the evidence.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to CIP-014-1, R6

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R6) Review evidence and verify the physical security plan(s) and the Requirement R4 evaluation have been reviewed by an unaffiliated third party. Also, review evidence and verify the following:
	(R6 Part 6.1) Reviewing party has the qualifications identified in Part 6.1.
	(R6 Part 6.2) Review is dated within 90 calendar days of completion of the Requirement R5 security plan.
	(R6 Part 6.3) Reviewing entity recommended changes to security plan(s) were made by entity or the reason(s) for not making the change(s) was/were documented within 60 calendar days of the completion of the unaffiliated third party review.
	(R6 Part 6.4) Review non-disclosure agreement (or other evidence) to verify procedures for protecting sensitive or confidential information between entity and third party were implemented.
Note to Auditor: The third party review may occur concurrent with or after the evaluation performed under Requirement R4 or the security plan develop under Requirement R5. See Guidelines and Technical Basis associated with the Standard for additional details related to qualifications of reviewing entities that may inform audited entities selection of a reviewing entity.	

Auditor Notes:

Additional Information:

Reliability Standard

The RSAW developer should provide the following information without hyperlinks. Update the information below as appropriate.

The full text of CIP-014-1 may be found on the NERC Web Site (www.nerc.com) under "Program Areas & Departments", "Reliability Standards."

In addition to the Reliability Standard, there is an applicable Implementation Plan available on the NERC Web Site.

In addition to the Reliability Standard, there is background information available on the NERC Web Site.

Capitalized terms in the Reliability Standard refer to terms in the NERC Glossary, which may be found on the NERC Web Site.

Sampling Methodology [If developer deems reference applicable]

Sampling is essential for auditing compliance with NERC Reliability Standards since it is not always possible or practical to test 100% of either the equipment, documentation, or both, associated with the full suite of enforceable standards. The Sampling Methodology Guidelines and Criteria (see NERC website), or sample guidelines, provided by the Electric Reliability Organization help to establish a minimum sample set for monitoring and enforcement uses in audits of NERC Reliability Standards.

Regulatory Language [Developer to ensure RSAW has been provided to NERC Legal for links to appropriate Regulatory Language – See example below]

E.g. FERC Order No. 742 paragraph 34: "Based on NERC's…….

E.g. FERC Order No. 742 Paragraph 55, Commission Determination: "We affirm NERC's…….

Selected Glossary Terms [If developer deems applicable]

The following Glossary terms are provided for convenience only. Please refer to the NERC web site for the current enforceable terms.

Revision History for RSAW

Version	Date	Reviewers	Revision Description
1	03/06/2015	Physical Security RSAW Task Force	New Document. Removed word 'widespread' from Requirement 1. Updated title page and footer for version 2.

[i] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

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DRAFT Reliability Standard Audit Worksheet[1]

CIP-014-2~~1~~ – Physical Security

This section to be completed by the Compliance Enforcement Authority.

Audit ID:	Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity:	Registered name of entity being audited
NCR Number:	NCRnnnnn
Compliance Enforcement Authority:	Region or NERC performing audit
Compliance Assessment Date(s)[2]:	Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method:	[On-site Audit | Off-site Audit | Spot Check]
Names of Auditors:	Supplied by CEA

[1] NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The NERC RSAW language contained within this document provides a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserves the right to request additional evidence from the registered entity that is not included in this RSAW. Additionally, this RSAW includes excerpts from FERC Orders and other regulatory references. The FERC order cites are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC orders, and the language included in this document, FERC orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

Applicability of Requirements *[RSAW developer to insert correct applicability]*

	BA	DP	GO	GOP	IA	LSE	PA	PSE	RC	RP	RSG	TO	TOP	TP	TSP
R1												X[3,4]			
R2												X[3,4]			
R3												X[3,4]			
R4												X[3,4]	X[4]		
R5												X[3,4]	X[4]		
R6												X[3,4]	X[4]		

Legend:

Text with blue background:	Fixed text – do not edit
Text entry area with Green background:	Entity-supplied information
Text entry area with white background:	Auditor-supplied information

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[3] Applicability is further defined to owners of transmission Facilities operated at 500 kV or higher (see section 4.1.1.1 of the Standard) and owners of certain transmission Facilities operating between 200 kV and 499 kV where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations, per section 4.1.1.2 of the Standard. In addition, sections 4.1.1.3 and 4.1.1.4 bring additional transmission Facilities identified as either critical to the derivation of Interconnection Reliability Operating Limits and Nuclear Plant Interface, respectively, within the purview of the standard. Please see the referenced sections of the Standard for additional details regarding applicability of the Requirements to Transmission Owners.

[4] Facilities in a "protected area," as defined in 10 C.F.R. § 73.2, within the scope of a security plan approved or accepted by the Nuclear Regulatory Commission are not subject to this Standard; or, Facilities within the scope of a security plan approved or accepted by the Canadian Nuclear Safety Commission are not subject to this Standard.

Findings

(This section to be completed by the Compliance Enforcement Authority)

Req.	Finding	Summary and Documentation	Functions Monitored

Req.	Areas of Concern

Req.	Recommendations

Req.	Positive Observations

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Subject Matter Experts

Identify the Subject Matter Expert(s) responsible for this Reliability Standard.

Registered Entity Response (Required; Insert additional rows if needed):

SME Name	Title	Organization	Requirement(s)

Note to Auditors Concerning Third Party Verifications and Reviews

Requirements R2 and R6 prescribe, respectively, unaffiliated third party verifications for Requirement R1 and unaffiliated third party reviews for Requirements R4 and R5. Auditors are encouraged to rely on the verifications and reviews performed in cases where the verifying or reviewing entities are qualified, unaffiliated with the audited entity, and the scope of their verification or review is clear. The concept of reliance means using the work of others to avoid duplication of efforts and is consistent with recognized professional auditing standards, which are required for Compliance Audits per NERC's Rules of Procedure. Reliance in the context of this Reliability Standard means using the Requirement R2 verifications and Requirement R6 reviews to reduce audit risk and the related rigor of audit testing for Requirements R1, R4, and R5. However, in cases where the verifying or reviewing entity lacks the qualifications specified in Requirement R2 for verifications or Requirement R6 for reviewers, the required unaffiliation from the audited entity, or where the scope of the third party entity's verification or review is unclear, auditors may need to apply audit testing of Requirements R1, R4, or R5. For this reason, the Evidence Requested and Compliance Assessment Approach Sections are still present in this RSAW for Requirements R1, R4, and R5. We anticipate those sections will also facilitate expectations for entities and their unaffiliated third party verifiers and reviewers, assist Electric Reliability Organization (ERO) auditors to understand the audit procedures applied by unaffiliated third party verifiers and reviewers, and provide transparency between ERO auditors and Industry, should circumstances require audit testing of Requirements R1, R4, or R5. Further, it is an objective of the ERO to have transparent Evidence Requests and Compliance Assessment Approaches for every enforceable standard, whether they are in audit scope or not.

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R1 Supporting Evidence and Documentation

R1. Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1.The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that, if rendered inoperable or damaged, could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection.

1.1. Subsequent risk assessments shall be performed:

- At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2)one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection; or
- At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in ~~widespread~~ instability, uncontrolled separation, or Cascading within an Interconnection.

1.2. The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.

M1. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the risk assessment of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria in Applicability Section 4.1.1 as specified in Requirement R1. Additionally, examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the identification of the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment as specified in Requirement R1, Part 1.2.

Registered Entity Response (Required):

Question: Do you own any Transmission stations/substations, either existing or planned in the next 24 months, meeting the applicability requirements of Section 4.1.1? ☐ Yes ☐ No

☐ This entity does not have any applicable Transmission stations/substations.

☐ Other: [Provide explanation below]

[Include additional information regarding the question here, including the type of response and format of the response requested, as appropriate.]

[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Compliance Narrative:

Provide a brief explanation of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
(R1) Provide the current and the immediately preceding dated risk assessments.
(R1) List of existing Transmission stations/substations that meet the criteria specified in Section 4.1.1.
(R1) List of Transmission stations/substations planned in the next 24 months that meet criteria specified in Section 4.1.1.
(R1 Part 1.2) List of primary control centers that operationally control each identified Transmission station/substation.

Registered Entity Evidence (Required):

The following information is required for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location of the evidence.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to CIP-014-1, R1

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R1) Review entity's process for determining Transmission stations/substations subject to identification in accordance with Requirement R1, including weighting described in Section 4.1.1.2.
	(R1) Review entity's risk assessment process to determine the Transmission stations/substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an interconnection.
	(R1) Ensure entity's risk assessment process includes Transmission stations/substations planned in the next 24 months.

	(R1) Ensure risk assessment(s) covers each Transmission station/substation meeting applicability described in Section 4.1.
	(R1 Part 1.1) If applicable, review any prior risk assessments and verify whether or not Transmission stations/substations were identified.
	(R1 Part 1.1) Review evidence that risk assessment was performed and verify that it occurred within the past 30 months where items were identified in the previous risk assessment and 60 months where no items were identified in the previous risk assessment.

Note to Auditor: Review entity's answer to the above Question and if the auditor can verify the answer is 'no,' Requirements R3-R6 do not apply and no further audit testing of Requirements R3-R6 is necessary, unless the entity performs the Transmission Operator function for a station/substation meeting the criteria of Requirement R1 Part 1.2.

The 24 month period referenced for Transmission stations/substations planned to be in service is as of the date of the risk assessment not the date of the audit.

See above Note Concerning Third Party Verifications for important details regarding audit risk assessment and related rigor of audit procedures to be applied for this Requirement.

Auditor Notes:

R2 Supporting Evidence and Documentation

R2. Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with or after the risk assessment performed under Requirement R1.

2.1. Each Transmission Owner shall select an unaffiliated verifying entity that is either:

- A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator;
- An entity that has transmission planning or analysis experience.

2.2. The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90 calendar days following the completion of the Requirement R1 risk assessment.

2.3. If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a s Transmission station or Transmission substation::

- Modify its identification under Requirement R1 consistent with the recommendation; or
- Document the technical basis for not modifying the identification in accordance with the recommendation.

2.4. Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated verifying entity and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M2. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner completed an unaffiliated third verification of the Requirement R1 risk assessment and satisfied all of the applicable provisions of Requirement R2, including, if applicable, documenting the technical basis for not modifying the Requirement R1 identification as specified under Part 2.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 2.4.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
(R2) Dated evidence of third party verification of the entity's risk assessment performed under Requirement R1.
(R2 Part 2.1) Documented qualifications of the verifying party.
(R2 Part 2.3) Recommendations, if any, of the verifying party related to Requirement R1 risk assessments.
(R2 Part 2.3) Documentation of modifications and implementation of recommendations or technical basis for not implementing recommendations of the verifying party.
(R2 Part 2.4) Evidence that procedures were implemented to protect sensitive and confidential information.

Registered Entity Evidence (Required):

The following information is required for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location of the evidence.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to CIP-014-1, R2

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R2) Review evidence of third party verification of the entity's risk assessment and verify the following:
	(R2 Part 2.1) The reviewing entity is registered in accordance with Part 2.1 or has transmission planning or analysis experience.
	(R2 Part 2.2) Verification was completed within 90 calendar days of risk assessment.
	(R2 Part 2.3) Verifying entity's recommendations, if any, were used to modify the entity's Requirement R1 identification or the technical basis for not modifying the Requirement R1 identification is documented within 60 calendar days of completion of the verification.
	(R2 Part 2.4) Review non-disclosure agreement (or other evidence) to verify procedures for protecting sensitive or confidential information between the entity and third party were implemented.
Note to Auditor See Guidelines and Technical Basis section of the standard and Rationale for Requirement R2 associated with the Standard for additional details regarding the term 'unaffiliated.'	

The third party verification may occur concurrent with or after the risk assessment performed under Requirement R1.

Auditor Notes:

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R3 Supporting Evidence and Documentation

R3. For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner, the Transmission Owner shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the primary control center of such identification and the date of completion of Requirement R2.

3.1. If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.

M3. Examples of acceptable evidence may include, but are not limited to, dated written or electronic notifications or communications that the Transmission Owner notified each Transmission Operator, as applicable, according to Requirement R3.

Registered Entity Response (Required):

Question: Are there any primary control centers identified in Requirement R1, Part 1.2 that are not under operational control of your NERC registration? ☐ Yes ☐ No

[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Compliance Narrative:

Provide a brief explanation of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
(R3) If applicable, dated communications with Transmission Operators demonstrating notification and the date of completion of Requirement R2.

Registered Entity Evidence (Required):

The following information is required for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location of the evidence.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to CIP-014-1, R3

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R3) For each applicable primary control center identified in Requirement R1 Part 1.2 not under the control of the entity's registration, verify notification exists and contains the date of completion of Requirement R2.
	(R3 Part 3.1) For each Transmission station/substation removed under Part 3.1, ensure the responsible Transmission Operator was notified of the removal within seven calendar days of removal from identification.
Note to Auditor: Note the entity's response to the above Question. If auditor can verify the entity's answer of 'No,' then Requirement R3 is not applicable and no further audit testing is required.	

Auditor Notes:

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R4 Supporting Evidence and Documentation

R4. Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following:

4.1. Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s);

4.2. Prior history of attack on similar facilities taking into account the frequency, geographic proximity, and severity of past physical security related events; and

4.3. Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.

M4. Examples of evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner or Transmission Operator conducted an evaluation of the potential threats and vulnerabilities of a physical attack to their respective Transmission station(s), Transmission substation(s) and primary control center(s) as specified in Requirement R4.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
(R4) A description of the entity's process for executing the evaluation prescribed in Requirement R4.
(R4) Dated evidence of the evaluation prescribed in Requirement R4.

Registered Entity Evidence (Required):

The following information is required for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location of the evidence.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to CIP-014-1, R4

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R4) Review evidence of evaluation and verify it considers the following:
	(R4) Potential threats and vulnerabilities as described in Requirement R4.
	(R4 Part 4.1) Unique characteristics as described in Requirement R4 Part 4.1.
	(R4 Part 4.2) Prior history of attack on similar facilities taking into account the frequency, geographic proximity, and severity of past physical security related events.
	(R4 Part 4.3) Intelligence or warnings as described in Part 4.3.
Note to Auditor: See above Note Concerning Third Party Verifications for important details regarding audit risk assessment and related rigor of audit procedures to be applied for this Requirement. Auditor should cross reference the Transmission stations/substations and primary control centers identified in the risk assessment performed under Requirement R1 to the evaluation prescribed in Requirement R4 to ensure it is complete.	

Auditor Notes:

R5 Supporting Evidence and Documentation

R5. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center identified in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s). The physical security plan(s) shall be developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes:

5.1. Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.

5.2. Law enforcement contact and coordination information.

5.3. A timeline for executing the physical security enhancements and modifications specified in the physical security plan.

5.4. Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).

M5. Examples of evidence may include, but are not limited to, dated written or electronic documentation of its physical security plan(s) that covers their respective identified and verified Transmission station(s), Transmission substation(s), and primary control center(s) as specified in Requirement R5, and additional evidence demonstrating execution of the physical security plan according to the timeline specified in the physical security plan.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
(R5) Dated physical security plan(s).

Registered Entity Evidence (Required):

The following information is required for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location of the evidence.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to CIP-014-1, R5

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R5) Review evidence and verify the physical security plan(s) covers the Transmission stations/substations and primary controls identified in Requirements R1 and/or R2, and verify plan was developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). In addition, verify the plan includes the following attributes:
	(R5 Part 5.1) Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.
	(R5 Part 5.2) Law enforcement contact and coordination information.
	(R5 Part 5.3) A timeline for executing physical security enhancements and modifications specified in the physical security plan.
	(R5 Part 5.4) Provisions to evaluate evolving physical threats, and their corresponding security measures in accordance with R5 Part 5.4
	(R5) Verify implementation of physical security plan(s). See 'Note to Auditor' for details.
Note to Auditor: See above Note Concerning Third Party Verifications for important details regarding audit risk assessment and related rigor of audit procedures to be applied for this Requirement. Auditor should cross reference the Transmission stations/substations and primary control centers identified in the risk assessment performed under Requirement R1 to the evaluation prescribed in Requirement R4 and the security plan(s) prescribed in Requirement R5 to ensure the plan addresses vulnerabilities to	

physical attacks per the evaluation conducted in Requirement R4.

Requirement R5 includes implementation of the security plan(s), which is not within the scope of the third party review described in Requirement R6. Auditors can gain reasonable assurance security plan(s) was/were implemented by determining if specific actions prescribed by the plan(s) have taken place within the timelines established by the plan(s). For example, if the plan calls for certain procedures to occur, then auditors could ask for evidence demonstrating the procedure has been implemented within the timeline established in the security plan. Also, if the plan calls for construction of a barrier, an auditor could verify evidence that such a barrier was constructed in accordance with the entity's timeline. As auditors should obtain reasonable, not absolute, assurance the plan(s) was/were implemented, testing implementation on a sample basis may be appropriate.

Auditor Notes:

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R6 Supporting Evidence and Documentation

R6. Each Transmission Owner identifies a Transmission station, Transmission substation, or primary control center identified in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5

6.1. Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following:

- An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.
- An entity or organization approved by the ERO.
- A governmental agency with physical security expertise.
- An entity or organization with demonstrated law enforcement, government, or military physical security expertise.

6.2. The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5.

6.3. If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:

- Modify its security plan(s) consistent with the recommendation; or
- Document the reason for not modifying the security plan(s) consistent with the recommendation

6.4. Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated reviewing entity and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M6. Examples of evidence may include, but are not limited to, written or electronic documentation that the Transmission Owner or Transmission Operator had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 as specified in Requirement R6 including, if applicable, documenting the reasons for not modifying the evaluation or security

plan(s) in accordance with a recommendation under Part 6.3. Examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 6.4

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
(R6) Dated Evidence of unaffiliated third party review of entity's Requirement R4 evaluation and Requirement R5 security plan(s).
(R6 Part 6.1) Evidence that reviewing entity staff meets qualifications identified in Part 6.1.
(R6 Part 6.3) Recommendations of reviewing party related to Requirement R4 evaluation and Requirement R5 security plan.
(R6 Part 6.3) Dated documentation of modifications and implementation of recommendations or reasons and compensating mitigating measures for not implementing recommendations of the reviewing party.
(R6 Part 6.4) Evidence that procedures were implemented to protect sensitive and confidential information.

Registered Entity Evidence (Required):

The following information is required for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location of the evidence.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to CIP-014-1, R6

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R6) Review evidence and verify the physical security plan(s) and the Requirement R4 evaluation have been reviewed by an unaffiliated third party. Also, review evidence and verify the following:
	(R6 Part 6.1) Reviewing party has the qualifications identified in Part 6.1.
	(R6 Part 6.2) Review is dated within 90 calendar days of completion of the Requirement R5 security plan.
	(R6 Part 6.3) Reviewing entity recommended changes to security plan(s) were made by entity or the reason(s) for not making the change(s) was/were documented within 60 calendar days of the completion of the unaffiliated third party review.
	(R6 Part 6.4) Review non-disclosure agreement (or other evidence) to verify procedures for protecting sensitive or confidential information between entity and third party were implemented.
Note to Auditor: The third party review may occur concurrent with or after the evaluation performed under Requirement R4 or the security plan develop under Requirement R5. See Guidelines and Technical Basis associated with the Standard for additional details related to qualifications of reviewing entities that may inform audited entities selection of a reviewing entity.	

Auditor Notes:

Additional Information:

Reliability Standard

The RSAW developer should provide the following information without hyperlinks. Update the information below as appropriate.

The full text of CIP-014-1 may be found on the NERC Web Site (www.nerc.com) under "Program Areas & Departments", "Reliability Standards."

In addition to the Reliability Standard, there is an applicable Implementation Plan available on the NERC Web Site.

In addition to the Reliability Standard, there is background information available on the NERC Web Site.

Capitalized terms in the Reliability Standard refer to terms in the NERC Glossary, which may be found on the NERC Web Site.

Sampling Methodology [If developer deems reference applicable]

Sampling is essential for auditing compliance with NERC Reliability Standards since it is not always possible or practical to test 100% of either the equipment, documentation, or both, associated with the full suite of enforceable standards. The Sampling Methodology Guidelines and Criteria (see NERC website), or sample guidelines, provided by the Electric Reliability Organization help to establish a minimum sample set for monitoring and enforcement uses in audits of NERC Reliability Standards.

Regulatory Language [Developer to ensure RSAW has been provided to NERC Legal for links to appropriate Regulatory Language – See example below]

E.g. FERC Order No. 742 paragraph 34: "Based on NERC's…….

E.g. FERC Order No. 742 Paragraph 55, Commission Determination: "We affirm NERC's…….

Selected Glossary Terms [If developer deems applicable]

The following Glossary terms are provided for convenience only. Please refer to the NERC web site for the current enforceable terms.

Revision History for RSAW

Version	Date	Reviewers	Revision Description
1	034/0~~9~~6/20145	Physical Security RSAW Task Force	New Document. Removed word 'widespread' from Requirement 1. Updated title page and footer for version 2.
~~2~~	~~05/01/2014~~	~~Physical Security RSAW Task Force~~	~~Revisions based on comments and changes to the standard.~~

[i] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2014-04 - Physical Security Directives

Mapping Document

Background

In Order No. 802 (final order on CIP-014-1 – Physical Security), issued on November 20, 2014, FERC directed NERC to remove the term "widespread" from Reliability Standard CIP-014-1 or, alternatively, to propose modifications to the Reliability Standard that address the Commission's concerns. FERC directed that NERC submit a responsive modification within six months from the effective date of this final rule.

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered	Removed the term "widespread" from Requirement R1	**R1.** Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection. *[VRF: High; Time-Horizon: Long-term Planning]* **1.1.** Subsequent risk assessments shall be performed: • At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection; or • At least once every 60 calendar months for a Transmission Owner that		inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. *[VRF: High; Time-Horizon: Long-term Planning]* **1.1.** Subsequent risk assessments shall be performed: • At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection; or • At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection. **1.2.** The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.		Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. **1.2.** The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.
R2. Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with	Retained from previous version	**R2.** Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with or

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
or after the risk assessment performed under Requirement R1. *[VRF: Medium; Time-Horizon: Long-term Planning]* **2.1.** Each Transmission Owner shall select an unaffiliated verifying entity that is either: • A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or • An entity that has transmission planning or analysis experience. **2.2.** The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90		after the risk assessment performed under Requirement R1. *[VRF: Medium; Time-Horizon: Long-term Planning]* **2.1.** Each Transmission Owner shall select an unaffiliated verifying entity that is either: • A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or • An entity that has transmission planning or analysis experience. **2.2.** The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
calendar days following the completion of the Requirement R1 risk assessment. **2.3.** If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation: • Modify its identification under Requirement R1 consistent with the recommendation; or • Document the technical basis for not modifying the identification in accordance with the recommendation.		calendar days following the completion of the Requirement R1 risk assessment. **2.3.** If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation: • Modify its identification under Requirement R1 consistent with the recommendation; or • Document the technical basis for not modifying the identification in accordance with the recommendation.

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
2.4. Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.		**2.4.** Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.
R3. For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the	Retained from previous version	**R3.** For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the

Standard: CIP-014-2, Physical Security		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
primary control center of such identification and the date of completion of Requirement R2. *[VRF: Lower; Time-Horizon: Long-term Planning]* **3.1.** If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.		primary control center of such identification and the date of completion of Requirement R2. *[VRF: Lower; Time-Horizon: Long-term Planning]* **3.1.** If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.
	Retained from previous version	

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R4. Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following: *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]* **4.1.** Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s); **4.2.** Prior history of attack on similar facilities taking into account the frequency,	Retained from previous version	**R4.** Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following: *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]* **4.1.** Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s); **4.2.** Prior history of attack on similar facilities taking into account the frequency,

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
geographic proximity, and severity of past physical security related events; and **4.3.** Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.		geographic proximity, and severity of past physical security related events; and **4.3.** Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.
R5. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and	Retained from previous version	**R5.** Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
primary control center(s). The physical security plan(s) shall be developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: *[VRF: High; Time-Horizon: Long-term Planning]* **5.1.** Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4. **5.2.** Law enforcement contact and coordination information. **5.3.** A timeline for executing the physical security enhancements and modifications specified in the physical security plan.		control center(s). The physical security plan(s) shall be developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: *[VRF: High; Time-Horizon: Long-term Planning]* **5.1.** Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4. **5.2.** Law enforcement contact and coordination information. **5.3.** A timeline for executing the physical security enhancements and modifications specified in the physical security plan.

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
5.4. Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).		**5.4.** Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).
R6. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5. *[VRF: Medium; Time-Horizon: Long-term Planning]*	Retained from previous version	**R6.** Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5. *[VRF: Medium; Time-Horizon: Long-term Planning]*

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
6.1. Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following: • An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification. • An entity or organization approved by the ERO. • A governmental agency with physical security expertise. • An entity or organization with demonstrated law enforcement, government, or military physical security expertise.		**6.1.** Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following: • An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification. • An entity or organization approved by the ERO. • A governmental agency with physical security expertise. • An entity or organization with demonstrated law enforcement, government, or military physical security expertise.

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
6.2. The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5. **6.3.** If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:		**6.2.** The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5. **6.3.** If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
• Modify its evaluation or security plan(s) consistent with the recommendation; or • Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation. **6.4.** Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.		• Modify its evaluation or security plan(s) consistent with the recommendation; or • Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation. **6.4.** Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2014-04: Physical Security

VRF and VSL Justifications for CIP-014-2

VRF and VSL Justifications – CIP-014-1, R1	
Proposed VRF	High
NERC VRF Discussion	Initial and subsequent risk assessments identify Transmission stations or Transmission substations that need to be assessed for threats and vulnerabilities and potential physical security measures. Since this is a Requirement in a planning time frame, a violation could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the risk assessment periodicity and the identification of the primary control center that has operational control of Transmission stations and/or Transmission substations.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable CIP-002-5.1 R1, which deals with categorizing cyber systems, is assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Transmission Owner performed an initial risk assessment but did so after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to two calendar months after that date;

VRF and VSL Justifications – CIP-014-1, R1	
	OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 30 calendar months but less than or equal to 32 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 60 calendar months but less than or equal to 62 calendar months.
Proposed Moderate VSL	The Transmission Owner performed an initial risk assessment but did so more than two calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to four calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 32 calendar months but less than or equal to 34 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 62 calendar months but less than or equal to 64 calendar months.
Proposed High VSL	The Transmission Owner performed an initial risk assessment but did so more than four calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to six calendar months after that date;

VRF and VSL Justifications – CIP-014-1, R1	
	OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 34 calendar months but less than or equal to 36 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 64 calendar months but less than or equal to 66 calendar months; OR The Transmission Owner performed a risk assessment but failed to include Part 1.2.
Proposed Severe VSL	The Transmission Owner performed an initial risk assessment but did so more than six calendar months after the date specified in the implementation plan for performing the initial risk assessment; OR The Transmission Owner failed to perform an initial risk assessment; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a risk assessment; OR The Transmission Owner that has not identified in its previous risk

VRF and VSL Justifications – CIP-014-1, R1	
	assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 66 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission station and Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a subsequent risk assessment.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if the risk assessment is not performed or if the risk assessment is not performed within required intervals.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – CIP-014-1, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to submit perform a risk assessment.

VRF and VSL Justifications – CIP-014-1, R2	
Proposed VRF	Medium
NERC VRF Discussion	Unaffiliated third party verification of initial and subsequent risk assessments provides reinforcement that the risk assessment was performed with due consideration to risk to the bulk power system. Since this Requirement is in a planning time frame, a violation could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. This justifies a Medium VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the unaffiliated third party verification including entities that may perform the verification, provisions for adding or removing Transmission stations and/or Transmission substations, and provisions for confidentiality of sensitive information.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-005-2 R6, which deals with verifying that its restoration plan accomplishes its intended function is assigned a medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so in more than 90 calendar days but less than or equal to 100 calendar days following completion of Requirement R1;

VRF and VSL Justifications – CIP-014-1, R2	
	OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by part 2.3 but did so more than 60 calendar days and less than or equal to 70 calendar days from completion of the third party verification.
Proposed Moderate VSL	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 100 calendar days but less than or equal to 110 calendar days following completion of Requirement R1; Or The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by part 2.3 but did so more than 70 calendar days and less than or equal to 80 calendar days from completion of the third party verification.
Proposed High VSL	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 110 calendar days but less than or equal to 120 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by part 2.3 but did so more than 80 calendar days from completion of the third party verification; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to modify or document the technical basis for not modifying its identification under R1 as required by part 2.3.
Proposed Severe VSL	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 120 calendar days following completion of Requirement R1; OR The Transmission Owner failed to have an unaffiliated third party

VRF and VSL Justifications – CIP-014-1, R2	
	verify the risk assessment performed under Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to implement procedures for protecting information per Part 2.4.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if an unaffiliated third party verification is not performed or if the verification is not performed within prescribe timelines. The VSLs are also written indicating violation of the Requirement Part regarding protection of information.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based	The VSL is assigned for a single instance of failing to have an unaffiliated third party verification performed; or failing to perform the verification within prescribe timelines; or failing to implement procedures to protect information.

VRF and VSL Justifications – CIP-014-1, R2	
on A Single Violation, Not on A Cumulative Number of Violations	

VRF and VSL Justifications – CIP-014-1, R3	
Proposed VRF	Lower
NERC VRF Discussion	Notifying the Transmission Operator that it has operational control of a Transmission station or Transmission substation identified in Requirement R1 and verified in Requirement R2 is necessary so that the Transmission Operator may begin performance of subsequent physical security requirements for the primary control center. This is a requirement that is administrative in nature and in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. This justifies a Lower VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the notification of the Transmission Operator regarding the removal of a Transmission station or Transmission substation.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-006-4 R6, which deals with notifying other entities so that Confirmed Interchange may be implemented, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than seven calendar days and less than or equal to nine calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than seven calendar

VRF and VSL Justifications – CIP-014-1, R3	
	days and less than or equal to nine calendar days following the verification or the subsequent risk assessment.
Proposed Moderate VSL	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than nine calendar days and less than or equal to 11 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than nine calendar days and less than or equal to 11 calendar days following the verification or the subsequent risk assessment.
Proposed High VSL	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 11 calendar days and less than or equal to 13 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 11 calendar days and less than or equal to 13 calendar days following the verification or the subsequent risk assessment.
Proposed Severe VSL	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 13 calendar days following the completion of Requirement R2; OR The Transmission Owner failed to notify the Transmission Operator that it operates a control center identified in Requirement R1; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 13 calendar days following the verification or the subsequent risk assessment. OR The Transmission Owner failed to notify the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1.

VRF and VSL Justifications – CIP-014-1, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if notification is not made subject to the conditions of the requirement.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to make the appropriate notification.

VRF and VSL Justifications – CIP-014-1, R4	
Proposed VRF	Medium
NERC VRF Discussion	Performing an evaluation of potential threats and vulnerabilities of a physical attack to each of respective Transmission station(s), Transmission substation(s), and primary control center(s) is necessary to ensure the physical security of those assets as well as the reliability of the bulk power system. Since this Requirement is in a planning time frame, a violation could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. This justifies a Medium VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the evaluation of potential threats and vulnerabilities of a physical attack to Transmission stations and/or Transmission substations.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable CIP-007-5 R2, which deals with a patch management process for tracking, evaluating, and installing cyber security patches for applicable Cyber Assets, is assigned a Medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A

VRF and VSL Justifications – CIP-014-1, R4	
Proposed Moderate VSL	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider one of Parts 4.1 through 4.3 in the evaluation.
Proposed High VSL	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider two of Parts 4.1 through 4.3 in the evaluation.
Proposed Severe VSL	The Responsible Entity failed to conduct an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1; OR The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider Parts 4.1 through 4.3.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if a responsible entity fails to conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) or failed to consider any of the Requirement Parts 4.1-4.3.

VRF and VSL Justifications – CIP-014-1, R4	
Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) or failing to consider any of the Requirement Parts 4.1-4.3.

VRF and VSL Justifications – CIP-014-1, R5	
Proposed VRF	High
NERC VRF Discussion	Development, implementation and execution of a documented physical security plan(s) that covers applicable Transmission station(s), Transmission substation(s), and primary control center(s) is necessary to ensure the physical security of those assets as well as the reliability of the bulk power system. Since this Requirement is in a planning time frame, a violation could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the physical security plan for applicable Transmission stations, Transmission substations, or primary control centers.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable CIP-003-3 R4, which deals with implementing and documenting a program to identify, classify, and protect information associated with Critical Cyber Assets, is assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 120 calendar days but less than or equal to 130 calendar days after completing Requirement R2;

VRF and VSL Justifications – CIP-014-1, R5	
	OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include one of Parts 5.1 through 5.4 in the plan.
Proposed Moderate VSL	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 130 calendar days but less than or equal to 140 calendar days after completing Requirement R2; OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include two of Parts 5.1 through 5.4 in the plan.
Proposed High VSL	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 140 calendar days but less than or equal to 150 calendar days after completing Requirement R2; OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include three of Parts 5.1 through 5.4 in the plan.
Proposed Severe VSL	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 150 calendar days after completing the verification in Requirement R2; OR The Responsible Entity failed to develop and implement a documented physical security plan(s) that covers its Transmission

VRF and VSL Justifications – CIP-014-1, R5	
	station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1. OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include Parts 5.1 through 5.4 in the plan.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if a responsible entity fails to develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s) or if the responsible entity failed to include any of the Requirement Parts 5.1-5.4.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level	The VSL is assigned for a single instance of failing to develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and

VRF and VSL Justifications – CIP-014-1, R5	
Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	primary control center(s) or failing to include any of the Requirement Parts 5.1-5.4.

VRF and VSL Justifications – CIP-014-1, R6	
Proposed VRF	Medium
NERC VRF Discussion	Unaffiliated third party review of the threat evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 provides reinforcement that these requirements were performed with due consideration to risk to the bulk power system. Since this Requirement is in a planning time frame, a violation could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. This justifies a Medium VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the unaffiliated third party review including entities that may perform the review, timelines for completing the review and provisions for confidentiality of sensitive information.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-005-2 R6, which deals with verifying that its restoration plan accomplishes its intended function is assigned a medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 90 calendar days but less than or equal to 100 calendar days;

VRF and VSL Justifications – CIP-014-1, R6	
	OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 60 calendar days and less than or equal to 70 calendar days following completion of the third party review.
Proposed Moderate VSL	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 100 calendar days but less than or equal to 110 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 70 calendar days and less than or equal to 80 calendar days following completion of the third party review.
Proposed High VSL	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so more than 110 calendar days but less than or equal to 120 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 80 calendar days following completion of the third party review; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did not and modify or document the reason for not modifying the security plan(s) as specified in Part 6.3.
Proposed Severe VSL	The Responsible Entity failed to have an unaffiliated third party

VRF and VSL Justifications – CIP-014-1, R6	
	review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 in more than 120 calendar days; OR The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but failed to implement procedures for protecting information per Part 6.3.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if an unaffiliated third party review is not performed or if the review is not performed within prescribe timelines. The VSLs are also written indicating violation of the Requirement Part regarding protection of information.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – CIP-014-1, R6	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to have an unaffiliated third party review performed; or failing to perform the review within prescribe timelines; or failing to implement procedures to protect information.

Consideration of Issues and Directives

Project 2014-04 - Physical Security Directives

January 27, 2015

Project 2014-04 - Physical Security Directives		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Paragraph 19. In addition to approving Reliability Standard CIP-014-1, the Commission adopts in part the NOPR proposal directing NERC to develop and submit modifications to the Reliability Standard concerning the use of the term "widespread" in Requirement R1. The Commission determines that the term "widespread" is unclear with respect to the obligations it imposes on applicable entities; how it would be implemented by applicable entities; and how it would be enforced. Accordingly, the Commission directs NERC, pursuant to FPA section 215(d)(5), to remove the term "widespread" from Reliability Standard CIP-014-1 or, alternatively, to propose modifications to the Reliability Standard that address the Commission's concerns. We direct that NERC submit a responsive	FERC Order 802 approving Reliability Standard CIO-014-1, Physical Security	The Physical Security Standard Drafting Team (PSSDT) revised CIP-014-1, Physical Security, by removing the term "widespread" from the standard. This was done in the Purpose Statement, Background Section, Requirement R1, the Rationale for Requirement R1 as well as the Guidance and Technical Basis Section of the standard. Additionally, the PSSDT has added the following to the Rationale and guideline and Technical Basis for Requirement R1: "The requirement is not to require identification of, and thus, not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event

Project 2014-04 - Physical Security Directives		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
modification within six months from the effective date of this final rule. Paragraph 35: Accordingly, pursuant to FPA section 215(d)(5), the Commission directs NERC to develop a modification to Reliability Standard CIP-014-1 that either removes the term "widespread" from Requirement R1 or, in the alternative, proposes changes that address the Commission's concerns. Further, we direct that NERC submit a responsive modification within six months from the effective date of this final rule. We recognize that certain entities commented on how NERC could modify Reliability Standard CIP-014-1 to address the Commission's stated concerns. However, we conclude that it is appropriate to allow NERC to develop and propose a modification in the first instance.		the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following: • Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6 • NERC EOP-004-2 reporting criteria • Area or magnitude of potential impact" Additionally, the PSSDT revised the Rationale for Requirement R1 as follows: "Requirement R1~~It~~ also meets the ~~portion of the~~ FERC directive ~~from paragraph 11~~ for periodic reevaluation of the risk assessment by requiring the risk assessment to be performed every 30 months (or 60 months for an entity that has not identified in a previous risk assessment) ~~any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an interconnection)~~."

Project 2014-04 - Physical Security Directives		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Paragraph 21. With respect to the informational filings proposed in the NOPR, the Commission adopts the proposal to direct NERC to make an informational filing addressing whether Reliability Standard CIP-014-1 provides physical security for all "High Impact" control centers, as that term is defined in Reliability Standard CIP-002-5.1, necessary for the reliable operation of the Bulk-Power System. However, the Commission extends the deadline for that informational filing until two years following the effective date of Reliability Standard CIP-014-1. Paragraph 57. The Commission adopts the NOPR proposal and directs NERC to submit an informational filing that addresses whether there is a need for consistent treatment of "High Impact" control centers for cybersecurity and physical security purposes through the development of Reliability Standards that afford physical protection to all "High Impact" control centers. The Commission, however, modifies the NOPR proposal and extends the due date for the informational filing to two years following the effective date of Reliability Standard CIP-014-1.	FERC Order 802 approving Reliability Standard CIO-014-1, Physical Security	NERC Staff will monitor implementation of Requirements R1 and R2 with respect to "High Impact" control centers as that term is defined in Reliability Standard CIP-002-5.1 as that term is defined in Reliability Standard CIP-002-5.1. NERC will submit an informational filing that addresses whether there is a need for consistent treatment of "High Impact" control centers for cybersecurity and physical security purposes through the development of Reliability Standards that afford physical protection to all "High Impact" control centers within two years following the effective date of Reliability Standard CIP-014-1.

Project 2014-04 - Physical Security Directives		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Paragraph 44. The Commission, instead, will focus its resources on carrying out compliance and enforcement activities to ensure that critical facilities are identified under Requirement R1. In its comments, NERC indicated that NERC staff will submit to the NERC Board of Trustees a report three months following implementation of Requirements R1, R2 and R3 concerning the scope of facilities identified as critical, including the number of facilities identified as critical and their defining characteristics. NERC also committed to sending this report to Commission staff.	FERC Order 802 approving Reliability Standard CIO-014-1, Physical Security	NERC Staff will monitor implementation of Requirements R1, R2 and R3 and will submit to the NERC Board of Trustees, a report three months following implementation of these Requirements concerning the scope of facilities identified as critical, including the number of facilities identified as critical and their defining characteristics. NERC will also submit this report to Commission staff.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, email this form to:
Barbara.Nutter@nerc.net

For questions about this form or for assistance in completing the form, call Barb Nutter at 404-446-9692.

NERC welcomes suggestions for improving the reliability of the Bulk-Power System through improved Reliability Standards. Please use this form to submit your proposal for a new NERC Reliability Standard or a revision to an existing standard.

Request to propose a new or a revision to a Reliability Standard			
Proposed Standard:	Project 2014-04 Physical Security Reliability Standard(s)		
Date Submitted:	March 12, 2014 (revised November 20, 2014)		
SAR Requester Information			
Name:	Stephen Crutchfield		
Organization:	NERC Staff		
Telephone:	609-651-9455	E-mail:	Stephen.crutchfield@nerc.net
SAR Type (Check as many as applicable)			
☒ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
On March 7, 2014, FERC issued an order directing the ERO to develop a standard to address the physical security of critical facilities on the Bulk-Power System. In the order, FERC stated: "The Commission directs the North American Electric Reliability Corporation (NERC), as the Commission-certified Electric Reliability Organization (ERO), to submit for approval one or more Reliability Standards that will require certain registered entities to take steps or demonstrate that they have taken steps to address physical security risks and vulnerabilities related to the reliable operation of the Bulk-Power System. The proposed Reliability Standards should require owners or operators of the Bulk-Power System, as appropriate, to identify facilities on the Bulk-Power System that are critical to the reliable operation of the Bulk-Power System. Then, owners or operators of those identified critical facilities should develop, validate and implement plans to protect against physical attacks that may compromise the operability or recovery of such facilities. The Commission directs NERC to submit the proposed Reliability Standards to the Commission within 90 days of the date of this order." *Reliability Standards for Physical Security Measures*, 146 FERC ¶ 61,166 at P 1 (2014) ("FERC Order"). In Order No. 802 (final order on CIP-014-1), issued on November 20, 2014, FERC directed NERC to remove the term "widespread" from Reliability Standard CIP-014-1 or, alternatively, to propose modifications to the Reliability Standard that address the Commission's concerns. FERC directed that NERC submit a responsive modification within six months from the effective date of this final rule.
SAR Information
Purpose or Goal (How does this request propose to address the problem described above?):
The primary goal of this SAR is to allow the Standard Drafting Team (SDT) for Project 2014-04, Physical Security to develop a standard(s) to address the directives of the March 7, 2014 FERC Order, and to address the one directive in Order 802 on the removal of the term widespread or alternatively propose modifications that address the Commission concerns in Order 802, and to ensure consistency within the NERC body of Reliability Standards.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
Provide clear, unambiguous requirements and standard(s) to address the directives in the March 7, 2014 FERC Order regarding the physical security of critical facilities on the Bulk-Power System, and to address the one directive in Order 802 on the removal of the term widespread or alternatively propose modifications that address the Commission concerns in Order 802.

SAR Information
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The SDT shall develop standard requirements, Violation Risk Factors, Violation Severity Levels, and implementation plan and shall work with compliance on an accompanying RSAW to address each of the directives in the March 7, 2014 FERC Order and to address the one directive in Order 802 on the removal of the term widespread or alternatively propose modifications that address the Commission concerns in Order 802.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The SDTs execution of this SAR requires the SDT to address each of the FERC directives in the deadline required by the Order and to address the one directive in Order 802 on the removal of the term widespread or alternatively propose modifications that address the Commission concerns in Order 802. The reliability assessment and justification is also set forth in the March 7, 2014 FERC Order. The March 7, 2014 FERC Order is incorporated in its entirety into this SAR, so as not to unnecessarily repeat or paraphrase the substance of the Order. There are no market interface impacts resulting from the standard action on physical security.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.

Reliability Functions	
☐ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐ Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐ Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒ Transmission Owner	Owns and maintains transmission facilities.
☒ Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐ Distribution Provider	Delivers electrical energy to the End-use customer.
☐ Generator Owner	Owns and maintains generation facilities.
☐ Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐ Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐ Market Operator	Interface point for reliability functions with commercial functions.
☐ Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

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

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

Related Standards	
Standard No.	Explanation
CIP-006-5 CIP-008-5 CIP-009-5	Review to ensure no language and terminology inconsistency with requirements developed under this project.

Related SARs	
SAR ID	Explanation
N/A	N/A

Regional Variances	
Region	Explanation
ERCOT	N/A
FRCC	N/A
MRO	N/A
NPCC	N/A
RFC	N/A
SERC	N/A
SPP	N/A

Regional Variances	
WECC	N/A

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NERC welcomes suggestions for improving the reliability of the Bulk-Power System through improved Reliability Standards. Please use this form to submit your proposal for a new NERC Reliability Standard or a revision to an existing standard.

Request to propose a new or a revision to a Reliability Standard			
Proposed Standard:	Project 2014-04 Physical Security Reliability Standard(s)		
Date Submitted:	March 12, 2014 (revised November 20, 2014)		
SAR Requester Information			
Name:	Stephen Crutchfield		
Organization:	NERC Staff		
Telephone:	609-651-9455	E-mail:	Stephen.crutchfield@nerc.net
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
On March 7, 2014, FERC issued an order directing the ERO to develop a standard to address the physical security of critical facilities on the Bulk-Power System. In the order, FERC stated: "The Commission directs the North American Electric Reliability Corporation (NERC), as the Commission-certified Electric Reliability Organization (ERO), to submit for approval one or more Reliability Standards that will require certain registered entities to take steps or demonstrate that they have taken steps to address physical security risks and vulnerabilities related to the reliable operation of the Bulk-Power System. The proposed Reliability Standards should require owners or operators of the Bulk-Power System, as appropriate, to identify facilities on the Bulk-Power System that are critical to the reliable operation of the Bulk-Power System. Then, owners or operators of those identified critical facilities should develop, validate and implement plans to protect against physical attacks that may compromise the operability or recovery of such facilities. The Commission directs NERC to submit the proposed Reliability Standards to the Commission within 90 days of the date of this order." *Reliability Standards for Physical Security Measures*, 146 FERC ¶ 61,166 at P 1 (2014) ("FERC Order"). In Order No. 802 (final order on CIP-014-1), issued on November 20, 2014, FERC directed NERC to remove the term "widespread" from Reliability Standard CIP-014-1 or, alternatively, to propose modifications to the Reliability Standard that address the Commission's concerns. FERC directed that NERC submit a responsive modification within six months from the effective date of this final rule.

SAR Information
Purpose or Goal (How does this request propose to address the problem described above?):
The primary goal of this SAR is to allow the Standard Drafting Team (SDT) for Project 2014-04, Physical Security to develop a standard(s) to address the directives of the March 7, 2014 FERC Order, and to address the one directive in Order 802 on the removal of the term widespread or alternatively propose modifications that address the Commission concerns in Order 802, and to ensure consistency within the NERC body of Reliability Standards.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
Provide clear, unambiguous requirements and standard(s) to address the directives in the March 7, 2014 FERC Order regarding the physical security of critical facilities on the Bulk-Power System, and to address the one directive in Order 802 on the removal of the term widespread or alternatively propose modifications that address the Commission concerns in Order 802.

SAR Information
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The SDT shall develop standard requirements, Violation Risk Factors, Violation Severity Levels, and implementation plan and shall work with compliance on an accompanying RSAW to address each of the directives in the March 7, 2014 FERC Order and to address the one directive in Order 802 on the removal of the term widespread or alternatively propose modifications that address the Commission concerns in Order 802.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The SDTs execution of this SAR requires the SDT to address each of the FERC directives in the deadline required by the Order and to address the one directive in Order 802 on the removal of the term widespread or alternatively propose modifications that address the Commission concerns in Order 802. The reliability assessment and justification is also set forth in the March 7, 2014 FERC Order. The March 7, 2014 FERC Order is incorporated in its entirety into this SAR, so as not to unnecessarily repeat or paraphrase the substance of the Order. There are no market interface impacts resulting from the standard action on physical security.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.

Reliability Functions	
☐ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐ Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐ Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒ Transmission Owner	Owns and maintains transmission facilities.
☒ Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐ Distribution Provider	Delivers electrical energy to the End-use customer.
☐ Generator Owner	Owns and maintains generation facilities.
☐ Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐ Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐ Market Operator	Interface point for reliability functions with commercial functions.
☐ Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

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

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

Related Standards	
Standard No.	Explanation
CIP-006-5 CIP-008-5 CIP-009-5	Review to ensure no language and terminology inconsistency with requirements developed under this project.

Related SARs	
SAR ID	Explanation
N/A	N/A

Regional Variances	
Region	Explanation
ERCOT	N/A
FRCC	N/A
MRO	N/A
NPCC	N/A
RFC	N/A
SERC	N/A
SPP	N/A

Regional Variances	
WECC	N/A

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2007-06 System Protection Coordination

Approvals Requested

- PRC-027-1 – Coordination of Protection System Performance During Faults
- PRC-001-3 – System Protection Coordination

Retirements Requested

- PRC-001-1.1(ii) – System Protection Coordination

Prerequisite Approvals

- N/A

Applicable Entities

Standard	Applicable Entities					
	TO	GO	DP	TOP	GOP	BA
PRC-027-1: Coordination of Protection System Performance During Faults	X	X	X			
PRC-001-3: System Protection Coordination				X	X	X

New or Modified Term(s) Used in NERC Reliability Standards

- None

Effective Date of New or Revised Standards

PRC-027-1 – Coordination of Protection System Performance During Faults

PRC-027-1 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

PRC-001-3 – System Protection Coordination

PRC-001-3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement

PRC-001-1.1(ii) – System Protection Coordination

PRC-001-1.1(ii) – System Protection Coordination shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter that is twelve (12) months after the date that the PRC-001-3 is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, PRC-001-1.1(ii) shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter that is twelve (12) months after the date that the PRC-001-3 is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Mapping of Requirements from PRC-001-1.1(ii) to PRC-027-1

Project 2007-06 System Protection Coordination

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.	Being addressed by Project 2007-06.2 Phase 2: System Protection Coordination	N/A
R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	Being addressed by Project 2007-06.2 Phase 2: System Protection Coordination	N/A

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows. R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. • Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition. R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.	PRC-027-1: R1 and R2 Note: Applicability changed to GO, TO and DP	R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process to develop settings for its BES Protection Systems to operate in the intended sequence during Faults. The process shall include: 1.1. A method to review and update the information required to develop new or revised Protection System settings. 1.2. A review of Protection System settings affected by System changes. 1.3. A review of existing entity-designated Protection System settings based on one of the following: • **Periodic Fault current studies:** A 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at the bus under study, and evaluated in a time interval not to exceed six calendar years, or • **Periodic review of Protection System settings:** A time interval, not to exceed six calendar years, or • A combination of the above. 1.4. A quality review of the Protection System settings prior to implementation.

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
		1.5. For new or revised Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities, (Transmission Owners, Generator Owners, and Distribution Providers), procedures to: 1.5.1. Communicate the proposed Protection System settings with the other functional entities. 1.5.2. Review proposed Protection System settings provided by other functional entities, and respond regarding the proposed settings. The response should identify any coordination issue(s) or affirm that no coordination issue(s) were identified. 1.5.3. Verify that any identified coordination issue(s) associated with proposed Protection System settings for the associated Elements are addressed prior to implementation. R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement the process established in accordance with Requirement R1.
R4. Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator	PRC-027-1: R1 and R2	R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process to develop settings for its BES Protection Systems to

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
Operators, Transmission Operators, and Balancing Authorities.	Note: Applicability changed to GO, TO and DP	operate in the intended sequence during Faults. The process shall include: 1.1. A method to review and update the information required to develop new or revised Protection System settings. 1.2. A review of Protection System settings affected by System changes. 1.3. A review of existing entity-designated Protection System settings based on one of the following: • **Periodic Fault current studies:** A 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at the bus under study, and evaluated in a time interval not to exceed six calendar years, or • **Periodic review of Protection System settings:** A time interval, not to exceed six calendar years, or • A combination of the above. 1.4. A quality review of the Protection System settings prior to implementation. 1.5. For new or revised Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
		entities (Transmission Owners, Generator Owners, and Distribution Providers), procedures to: 1.5.1. Communicate the proposed Protection System settings with the other functional entities. 1.5.2. Review proposed Protection System settings provided by other functional entities, and respond regarding the proposed settings. The response should identify any coordination issue(s) or affirm that no coordination issue(s) were identified. 1.5.3. Verify that any identified coordination issue(s) associated with proposed Protection System settings for the associated Elements are addressed prior to implementation. R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement the process established in accordance with Requirement R1.
R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:	Being addressed by Project 2007-06.2 Phase 2: System Protection Coordination	N/A

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems. R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.		
R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Remedial Action Scheme in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.	Being addressed by Project 2007-06.2 Phase 2: System Protection Coordination	N/A

A. Introduction

1. Title: **System Protection Coordination**

2. Number: PRC-001-~~3~~1.1~~(ii)~~

3. Purpose:

To ensure system protection is coordinated among operating entities.

4. Applicability

4.1. Balancing Authorities

4.2. Transmission Operators

4.3. Generator Operators

5. Effective Date:

See the Implementation Plan for PRC-001-~~3~~, Project 2007-06 System Protection Coordination.~~1.1(ii).~~

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:

R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.

R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

~~**R3.** A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.~~

~~**R4.0.** Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.~~

- ~~Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.~~

~~**R6.0.** Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.~~

~~**R7.** Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.~~

~~**R8.**~~**R3.** A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:

~~**R8.1.**~~**R3.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.

~~**R8.2.**~~**R3.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.

~~**R9.**~~**R4.** Each Transmission Operator and Balancing Authority shall monitor the status of each Remedial Action Scheme in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

C. Measures

~~**M1.** Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.~~

~~**M2.**~~**M1.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Remedial Action Schemes in its area. (Requirement ~~6~~ 4 Part 1)

~~**M3.**~~**M2.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Remedial Action Schemes. (Requirement ~~6~~ 4 Part 2)

D. Compliance

Updated to current pro forma language

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority ~~Monitoring Responsibility~~

~~Regional~~ As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards ~~Reliability Organizations shall be responsible for compliance monitoring.~~

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. ~~Data~~ Evidence Retention

~~Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.~~

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures ~~2~~ 1 and ~~3~~2.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

~~Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,~~

The Compliance ~~Monitor~~ Enforcement Authority shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Generator Operators:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: ~~Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1~~Not applicable.~~.~~

3. Levels of Non-Compliance for Transmission Operators:

3.1. Level 1: Not applicable.

3.2. **Level 2**: Not applicable.

3.3. **Level 3**: Not applicable.

3.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

~~3.4.1 Failed to provide evidence of coordination when installing new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities as specified in R3.2.~~

~~3.4.2~~3.4.1 Did not monitor the status of each Remedial Action Scheme, or did not notify affected Transmission Operators, Balancing Authorities of changes in Remedial Action Scheme status as specified in ~~R6~~R4.

4. **Levels of Non-Compliance for Balancing Authorities:**

4.1. **Level 1:** Not applicable.

4.2. **Level 2**: Not applicable.

4.3. **Level 3**: Not applicable.

4.4. **Level 4:** Did not monitor the status of each Remedial Action Scheme, or did not notify affected Transmission Operators, Balancing Authorities of changes in Remedial Action Scheme status as specified in ~~R6~~R4.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	August 25, 2005	Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0	Errata
1	November 1, 2006	Adopted by the NERC Board of Trustees	Revised
1.1	April 11, 2012	Errata adopted by the Standards Committee; (Capitalized “Protection System” in accordance with Implementation Plan for Project 2007-17 approval of revised definition of “Protection System”)	Errata associated with Project 2007-17
1.1	September 9, 2013	Informational filing submitted to reflect the revised definition of Protection System in accordance with the	

		Implementation Plan for the revised term.	
1.1(i)	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
1.1(ii)	February 12, 2015	Adopted by the NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources
2	May 9, 2012	Adopted by Board of Trustees	Deleted Requirements R2, R5, and R6.
3	TBD	Adopted by Board of Trustees	Deleted Requirements R3 and R4.

~~Rationale:~~

~~During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.~~

~~Rationale for the Applicability Exclusion in Requirement R3.1~~

~~Coordination of new or changes to protective systems associated with dispersed power producing resources identified through Inclusion I4 of the BES definition are typically performed on the interconnecting facilities. New or changes to protective systems associated with these facilities should be coordinated with the TOP as these protective systems typically must be closely coordinated with the transmission protective systems to ensure the overall protection systems operates as designed. While the protective systems implemented on the individual generating units of dispersed power producing resources at these dispersed power producing facilities (i.e. individual wind turbines or solar panels/inverters) may in some cases need to be coordinated with other protective systems within the same dispersed power producing facility, new or changes to these protective systems do not need to be coordinated with the transmission protective systems, as this coordination would not provide reliability benefits to the BES.~~

A. Introduction

1. Title: **System Protection Coordination**

2. Number: PRC-001-3

3. Purpose:

To ensure system protection is coordinated among operating entities.

4. Applicability

4.1. Balancing Authorities

4.2. Transmission Operators

4.3. Generator Operators

5. Effective Date:

See the Implementation Plan for PRC-001-3, Project 2007-06 System Protection Coordination.

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:

R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.

R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

R3. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:

R3.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.

R3.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.

R4. Each Transmission Operator and Balancing Authority shall monitor the status of each Remedial Action Scheme in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

C. Measures

M1. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Remedial Action Schemes in its area. (Requirement 4 Part 1)

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Remedial Action Schemes. (Requirement 4 Part 2)

D. Compliance

Updated to current pro forma language

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Evidence Retention

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures 1 and 2.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

The Compliance Enforcement Authority shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Generator Operators:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

3. Levels of Non-Compliance for Transmission Operators:

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

3.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Did not monitor the status of each Remedial Action Scheme, or did not notify affected Transmission Operators, Balancing Authorities of changes in Remedial Action Scheme status as specified in R4.

4. Levels of Non-Compliance for Balancing Authorities:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: Did not monitor the status of each Remedial Action Scheme, or did not notify affected Transmission Operators, Balancing Authorities of changes in Remedial Action Scheme status as specified in R4.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

0	August 25, 2005	Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0	Errata
1	November 1, 2006	Adopted by the NERC Board of Trustees	Revised
1.1	April 11, 2012	Errata adopted by the Standards Committee; (Capitalized “Protection System” in accordance with Implementation Plan for Project 2007-17 approval of revised definition of “Protection System”)	Errata associated with Project 2007-17
1.1	September 9, 2013	Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.	
1.1(i)	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
1.1(ii)	February 12, 2015	Adopted by the NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources
2	May 9, 2012	Adopted by Board of Trustees	Deleted Requirements R2, R5, and R6.
3	TBD	Adopted by Board of Trustees	Deleted Requirements R3 and R4.

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Violation Risk Factor and Violation Severity Level Justification Document

Project 2007-06 System Protection Coordination

This document provides the standard drafting team (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-027-1. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the

preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange

- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for PRC-027-1, Requirement R1	
VRF for Requirement R1 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because an entity's failure to establish a process to develop settings for its BES Protection Systems to operate in the intended sequence during Faults could directly affect the electrical state or the capability of the Bulk-Power System. However, a violation of this requirement is unlikely to lead to Bulk-Power System instability, separation, or cascading failures. A medium VRF assignment is appropriate given the level of risk to System performance resulting from the lack of coordinated Protection Systems. For these reasons, the requirement meets the NERC criteria for a Medium VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R1 relates to two of these areas, specifically (i) protection systems and their coordination; and (ii) system modeling and data exchange. Requirement R1 mandates that entities establish a process to address all aspects of BES Protection System coordination, including the updating of modeling information and the exchange of Protection System data with other owners when applicable (see, Requirement R1, Parts 1.1 and 1.5).

VRF Justifications for PRC-027-1, Requirement R1	
VRF for Requirement R1 is Medium	
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	Because Parts (previously called sub-Requirements) are no longer assigned individual VRFs, this Guideline is no longer applicable.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-005-2, Requirements R1 and R2 which are related to developing and documenting a Protection System Maintenance Program and have VRFs of Medium.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because an entity's failure to establish a process to develop settings for its BES Protection Systems to operate in the intended sequence during Faults could directly affect the electrical state or the capability of the Bulk-Power System. However, a violation of this requirement is unlikely to lead to Bulk-Power System instability, separation, or cascading failures. A medium VRF assignment is appropriate given the level of risk to System performance resulting from the lack of coordinated Protection Systems. For these reasons, the requirement meets the NERC criteria for a Medium VRF.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-027-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The responsible entity established a process in accordance with Requirement R1, but failed to include one Part.	The responsible entity established a process in accordance with Requirement R1, but failed to include two or more Parts. OR The responsible entity failed to establish a process in accordance with Requirement R1.

VSL Justifications for PRC-027-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-001-1.1(ii), Requirements R3 and R4, so there is no "consequence of lowering the current level of compliance."
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the Severe and High VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-027-1, Requirement R1	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-027-1, Requirement R2	
VRF for Requirement R2 is High	
NERC VRF Discussion	A high VRF is appropriate for Requirement R2 because failure to implement the process established in Requirement R1 could, "under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition." This requirement meets the NERC criteria for a High VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the BPS. Requirement R2 relates to two of these areas, specifically (i) protection systems and their coordination; and (ii) system modeling and data exchange. Requirement R2 mandates that entities implement the process established in Requirement R1 that incorporates all actions necessary to achieve coordination of Protection Systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	Because Parts (previously called sub-Requirements) are no longer assigned individual VRFs, this Guideline is no longer applicable.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-005-2, Requirements R3 and R4 which are related to implementing time-based and performance-based maintenance program(s) respectively for Protection Systems.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A high VRF is appropriate for Requirement R2 because failure to implement the process established in Requirement R1 could, "under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition." This requirement meets the NERC criteria for a High VRF.

VRF Justifications for PRC-027-1, Requirement R2	
VRF for Requirement R2 is High	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-027-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The responsible entity implemented the process established in accordance with Requirement R1, but failed to implement one Part.	The responsible entity implemented the process established in accordance with Requirement R1, but failed to implement two or more Parts. OR The responsible entity failed to implement the process established in accordance with Requirement R1.

VSL Justifications for PRC-027-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-001-1.1(ii), Requirements R3 and R4, so there is no "consequence of lowering the current level of compliance."
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the Severe and High VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-027-1, Requirement R2	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

The System Protection Coordination Standard Drafting Team (SPCSDT) created a new results-based standard, PRC-027-1, with the stated purpose: "To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements, such that the Protection System components operate in the intended sequence during Faults." PRC-027-1 clarifies the coordination aspects and incorporates the reliability objectives of Requirements R3 and R4 from PRC-001-1.1(ii). Draft 5 of PRC-027-1 modifies the applicability of the standard to include "Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements," whereas, prior drafts of the standard limited the applicability to "Protection Systems installed for the purpose of detecting Faults on Interconnecting Elements." With this change to the applicability, the coordination of Protection Systems for all "internal" or "intra-entity" connections between BES Elements are addressed.

Completed Actions	Date
Standard Authorization Request (SAR) posted for comment	June 11 – July 10, 2007
SAR approved	August 13, 2007
Draft 1 of PRC-001-2 posted for comment	September 11 – October 26, 2009
Draft 1 of PRC-027-1 posted for formal comment with ballot	May 21 – July 5, 2012
Draft 2 of PRC-027-1 posted for formal comment with ballot	November 16 – December 17, 2012
Draft 3 of PRC-027-1 posted for formal comment with ballot	June 4 – July 3, 2013.
Draft 4 of PRC-027-1 posted for formal comment with ballot	November 4 – December 31, 2013
Draft 5 of PRC-027-1 posted for informal comment	October 1 – October 21, 2014

Draft 5 of PRC-027-1 posted for formal comment with ballot	April 1 – May 15, 2015

Anticipated Actions	Date
10-day final ballot	June, 2015
NERC Board (BOT) adoption	August, 2015

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

N/A

Protection System Issues Addressed by Other Projects:

Fault clearing is the only aspect of protection coordination addressed by Reliability Standard PRC-027-1. Other protection issues, such as over/under frequency, over/under voltage, coordination of generating unit or plant voltage regulating controls, and relay loadability are addressed by the following existing standards or current projects:

- Underfrequency Load shedding programs are addressed in PRC-006-2.
- Undervoltage Load shedding programs are addressed in PRC-010-1.
- Generator performance during declined frequency and voltage excursions is addressed in PRC-024-1.
- Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection is addressed in PRC-019-1.
- Transmission relay loadability is addressed in PRC-023-3.
- Generator relay loadability is addressed in PRC-025-1.
- Protective relay response during stable power swings is addressed in PRC-026-1.
- Protection System Misoperations (including those caused by coordination issues) are addressed in PRC-004-3.

The SPCSDT contends that including aspects of protection coordination other than Fault coordination within PRC-027-1 would cause duplication or conflict with requirements and compliance measurements of other standards.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** **Coordination of Protection System Performance During Faults**

2. **Number:** PRC-027-1

3. **Purpose:** To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements, such that the Protection Systems operate in the intended sequence during Faults.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Transmission Owner

   4.1.2. Generator Owner

   4.1.3. Distribution Provider (that owns Protection Systems identified in the Facilities section 4.2 below)

   4.2. Facilities:

   Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements

5. **Effective Date:**
   See Implementation Plan for PRC-027-1, Project 2007-06 System Protection Coordination.

B. Requirements and Measures

Rationale for Requirement R1:

Coordinated Protection Systems enhance BES reliability by reducing the risk of power system instability or Cascading by isolating the faulted equipment in a timely manner – leaving the remainder of the System operational and capable of withstanding the next contingency. When Faults occur, properly coordinated protection systems minimize the number of power system Elements removed from service and protect power system equipment from damage. The stated purpose of this standard is: To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements, such that the Protection Systems operate in the intended sequence during Faults. Requirement R1 captures this intent by mandating an entity establish a process that, when followed, will facilitate consistent results for developing settings for its BES Protection Systems. The drafting team contends the parts listed below are essential elements of the coordination process.

Part 1.1 Reviewing and updating the information required to coordinate Protection Systems maximizes the likelihood that the process of reviewing and developing settings is completed using accurate, up-to-date information. Examples of information that potentially need to be reviewed are: short-circuit databases, line and transformer impedances, station configurations, current and voltage transformer ratios, adjacent Protection System settings, and relay and control functional drawings.

Part 1.2 Reviewing the affected Protection System settings when System changes occur maintains coordination. Examples of System changes are: new or revised Protection System installations, changes to a transmission system Element that alters any sequence or mutual coupling impedance, changes to generator unit(s) that result in a change in impedance, or changes to the generator step-up transformer(s) that result in a change in impedance.

Part 1.3 Periodically reviewing Fault current values and/or existing entity-designated Protection System settings maximizes the likelihood that small incremental changes to the power system have not altered the coordination of the Protection Systems. Based on the Protection System design and/or susceptibility to changes in Fault current, applicable entities (Transmission Owners, Generator Owners, and Distribution Providers) will designate what Protection Systems must be included in the review(s) to ensure these Protection Systems continue to operate in the intended sequence during Faults. For example, a current differential scheme may not need to be included because changes in Fault current will not affect the coordination of this system. However, an instantaneous overcurrent element would need to be reviewed because changes in Fault current may cause this element to operate for Faults outside its zone of protection. Part 1.3 provides entities the flexibility to use a Fault current-based or a time-based methodology, or a combination of the two.

The Fault current-based option requires an entity to first establish a Fault current baseline for Protection Systems at the bus under study to be used as a control point for future Fault current studies. Fault current changes on the System are usually small and occur gradually over time. The accumulation of these incremental changes could affect the performance of Protection Systems during Fault conditions. To minimize this risk, the drafting team chose a maximum Fault current deviation of 15 percent (as compared to the entity-established baseline) and a maximum time interval of six calendar years for the Fault current analysis to be performed. The drafting team contends these maximums provide an entity with latitude to choose a Fault current threshold and time interval that best matches its protection philosophy, Protection System maintenance schedule, or other business considerations. (See the Supplemental Materials section for more detailed discussion.)

As a second option, an entity may choose to establish a periodic review of its existing Protection System settings. The maximum time interval for the review is six calendar years. The drafting team assigned a six calendar year time interval because that corresponds to the maximum allowable maintenance period established for certain relays

in PRC-005-2; consequently, this allows Protection System settings revisions to be included with associated maintenance.

As a third option, an entity may choose to apply a combination of the two review methodologies based on criteria such as voltage level or Protection System application.

Part 1.4 A quality review of the Protection System settings minimizes the introduction of human error into the development of Protection System settings and helps to ensure the settings produced meet the entity's design specifications for Protection System performance. Peer reviews, automated checking programs, and entity-developed review procedures, are all examples of quality reviews.

Part 1.5 The coordination of Protection Systems associated with BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers) is critical to the reliability of the BES. Communications among these entities is essential so potential coordination issues can be identified and addressed prior to implementation of any proposed Protection System changes.

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process to develop settings for its BES Protection Systems to operate in the intended sequence during Faults. The process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A method to review and update the information required to develop new or revised Protection System settings.

1.2. A review of Protection System settings affected by System changes.

1.3. A review of existing entity-designated[1] Protection System settings based on one of the following:

- **Periodic Fault current studies:** A 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at the bus under study, and evaluated in a time interval not to exceed six calendar years, or
- **Periodic review of Protection System settings:** A time interval, not to exceed six calendar years, or
- A combination of the above.

1.4. A quality review of the Protection System settings prior to implementation.

[1] Based on the Protection System design and/or susceptibility to changes in Fault current, applicable entities (Transmission Owners, Generator Owners, and Distribution Providers) will designate what Protection Systems must be included in the review(s) to ensure these Protection Systems continue to operate in the intended sequence during Faults.

1.5. For new or revised Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities, (Transmission Owners, Generator Owners, and Distribution Providers), procedures to:

1.5.1. Communicate the proposed Protection System settings with the other functional entities.

1.5.2. Review proposed Protection System settings provided by other functional entities, and respond regarding the proposed settings. The response should identify any coordination issue(s) or affirm that no coordination issue(s) were identified.

1.5.3. Verify that any identified coordination issue(s) associated with proposed Protection System settings for the associated Elements are addressed prior to implementation.

M1. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the responsible entity established a process to develop settings for its BES Protection Systems, in accordance with Requirement R1.

Rationale for Requirement R2:

Implementing the process established in Requirement R1 ensures a consistent approach to the development of Protection System settings such that BES Protection Systems operate in the intended sequence during Faults.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement the process established in accordance with Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M2. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the responsible entity implemented the process established in accordance with Requirement R1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask

an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner, Generator Owner and Distribution Provider that owns Protection Systems designed to detect Faults on BES Elements shall each keep data or evidence to show compliance with Requirements R1 and R2, and Measures M1 and M2, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner, Generator Owner or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved, or for the time specified above, whichever is longer.

The The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	The responsible entity established a process in accordance with Requirement R1, but failed to include one Part.	The responsible entity established a process in accordance with Requirement R1, but failed to include two or more Parts. OR The responsible entity failed to establish a process in accordance with Requirement R1.
R2.	N/A	N/A	The responsible entity implemented the process established in accordance with Requirement R1, but failed to implement one Part.	The responsible entity implemented the process established in accordance with Requirement R1, but failed to implement two or more Parts. OR The responsible entity failed to implement the process established in accordance with Requirement R1.

D. Regional Variances

None.

E. Associated Documents

NERC System Protection and Control Subcommittee – Technical Reference Document "Power Plant and Transmission System Protection Coordination" (the most current version).

NERC System Protection and Control Task Force – Assessment of Standard PRC-001-0 – System Protection Coordination (December 7, 2006)

NERC System Protection and Control Task Force – The Complexity of Protecting Three-Terminal Transmission Lines (September 2006)

Implementation Plan **(DELETE GREEN TEXT PRIOR TO PUBLISHING) A link should be added to the implementation plan and other important documents associated with the standard once finalized.**

Version History

Version	Date	Action	Change Tracking
1	TBD	Adopted by NERC Board of Trustees	New

Purpose:

To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements, such that the Protection Systems operate in the intended sequence during Faults.

Coordinated Protection Systems enhance BES reliability by reducing the risk of power system instability or Cascading by isolating the faulted equipment in a timely manner – leaving the remainder of the System operational and capable of withstanding the next contingency. When Faults occur, properly coordinated protection systems minimize the number of power system Elements removed from service and protect power system equipment from damage. This standard requires that entities establish and implement a process to coordinate their BES Protection Systems to operate in the intended sequence during Faults.

Requirement R1:

The requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process to develop settings for its BES Protection Systems to operate in the intended sequence during Faults.

This requirement directs the applicable entities to establish a process to develop settings for coordinating its BES Protection Systems such that they operate in the intended sequence during Faults. The drafting team contends the items included as elements of the process are key to ensuring the development of accurate settings, as well as providing internal and external checks to minimize the possibility of errors in the development of these settings.

In developing this Standard, the System Protection Coordination Standard Drafting Team (SPCSDT) referenced various publications that discuss protective relaying theory and application. The following description of “coordination of protection” is from the pending revision of IEEE C37.113, Guide for Protective Relay Applications to Transmission Lines:

> *“The process of choosing current or voltage settings, or time delay characteristics of protective relays such that their operation occurs in a specified sequence so that interruption to customers is minimized and least number of power system elements are isolated following a system fault.”*

The drafting team acknowledges that entities may have differing technical criteria for the development of Protection System settings based on their own internal tolerances. These philosophies can vary based on system topology, protection technology utilized, as well as historical knowledge. As such, a single definition or criteria for ‘Protection System coordination’ is not practical.

The drafting team also recognizes that the coordination of some Protection Systems may seem unnecessary, such as for a line that is protected by dual current differential relays. Where backup Protection Systems are enabled to operate based on current level or apparent impedance with some definite or inverse time delay, it is important to ensure those Protection Systems coordinate with other Elements’ Protection Systems such that tripping does not unnecessarily occur for Faults outside of the differential zone.

Part 1.1 A method to review and update the information required to develop new or revised Protection System settings.

Two important studies used by protection engineers to develop Protection System settings for Transmission Owners, Generator Owners, and Distribution Providers are the short circuit and protective device coordination studies. Having a method of reviewing and updating information to make sure it is correct in short circuit studies and protective device coordination studies is necessary to guarantee that these two studies accurately reflect the physical power system being considered in the development of Protection System relay settings. The results of the studies are only as accurate as the information that their calculations are based on.

A short circuit study is an analysis of an electrical network that determines the magnitude of the currents flowing in the network during an electrical Fault. The results of a short circuit study are used as the basis for protective device coordination studies. Because a short circuit study should, as accurately as possible, model the actual network it is representing in order to calculate true Fault currents, the method of the review and update of information for the short circuit study might include the following:

1. A review of applicable BES line, transformer, and generator impedances to verify they are correct.
2. A review of the network model to confirm the network in the study accurately reflects the configuration of the actual system, or how the system will be configured when the proposed relay settings are installed.
3. A review of interconnected Transmission Owner, Generator Owner, or Distribution Provider's information to determine whether their Systems are correctly modeled in the short circuit study.

A protective device coordination study is performed to determine the settings for protective relays to operate in the intended sequence during Faults. Protective device coordination studies are used to evaluate the application of protective devices, identify problem areas in the network, and determine solutions for existing or future device coordination.

A protective device coordination study should, as accurately as possible, represent the actual or proposed protective relaying in the network. The method for reviewing and updating information for the protective device coordination study might include the following:

1. A review of current and voltage transformer ratios, Protection System settings and the relay manufacture's curve characteristics to ensure the information in the protective device coordination study is correct.
2. A review of the adjacent relay settings to ensure those settings coordinate with the relay settings under study.
3. A review of interconnected Transmission Owner, Generator Owner, or Distribution Provider's actual and proposed relay setting changes to determine whether they are accurately represented in the protective device coordination study.

Other information that may be of value includes engineering drawings such as single-line diagrams, three-line diagrams, and relay and control functional drawings.

Part 1.2 A review of Protection System settings affected by System changes.

Reviewing the affected Protection System settings when System changes occur maintains coordination. Examples of System changes are: new or revised Protection System installations, changes to a transmission system Element that alter any sequence or mutual coupling impedance, changes to generator unit(s) that result in a change in impedance, or changes to the generator step-up transformer(s) that result in a change in impedance.

Part 1.3 A review of existing entity-designated Protection System settings based on one of the following:

Periodically reviewing Fault current values and/or existing entity-designated Protection System settings maximizes the likelihood that small incremental changes to the power system have not altered the coordination of the Protection Systems. Based on the Protection System design and/or susceptibility to changes in Fault current, an entity will designate what Protection Systems must be included in the review to ensure these Protection Systems continue to operate in the intended sequence during Faults. For example, a current differential scheme may not need to be included because changes in Fault current will not affect the coordination of this system. However, settings for an instantaneous overcurrent element would need to be reviewed because changes in Fault current may cause this element to operate for Faults outside its zone of protection. Based on stakeholder comments and industry knowledge, the drafting team chose two 'triggers' for initiating a review of existing Protection System settings. Entities have the flexibility to use a Fault current-based or a time-based methodology, or a combination of the two.

- (Option 1) A 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at the busunder study, and evaluated in a time interval not to exceed six calendar years, or Fault current changes on the System are usually small and occur gradually over time. The accumulation of these incremental changes could affect the performance of Protection Systems during Fault conditions. To minimize this risk, the drafting team chose a maximum Fault current deviation of 15 percent (when compared to the entity-established baseline) and a maximum time interval of six calendar years for the Fault current analysis to be performed. The drafting team contends these maximums provide an entity with latitude to choose a Fault current threshold and time interval that best matches its protection philosophy, Protection System maintenance schedule, or other business considerations. The Fault current-based option requires an entity to first establish a Fault current baseline to be used as a control point for future Fault current studies. The Fault current values used in the percent change calculation, whether three-phase or phase-to-ground Fault currents, are typically determined with maximum generation and all Facilities assumed to be in service.

  The baseline can be the Fault currents used for initial settings development, or where not available, the Fault current values from the most recent short-circuit study available at the time the standard goes into effect. These baseline Fault

current values can be at the bus level or at the individual Element level. When performing the periodic Fault current comparison, the entity would continue to compare actual Fault current values gathered during the review against the originally established baseline values until a condition occurs that necessitates the establishment of a new baseline.

Example: Baseline is established at 10,000 amps. During the first short-circuit review, it is discovered that Fault current has increased to 11,250 amps (12.5 % change); consequently, no Protection System settings review is required since the increase is below 15% and the baseline value for next review remains at 10,000 amps. However, during the next short-circuit review, the Fault current has increased to 11,500 (15% change); therefore, a review of the Protection System settings is required, and a new baseline of 11,500 amps would be established.

- (Option 2) A time interval, not to exceed six calendar years, or

  As a second option, an entity may choose a time-based methodology to review Protection System settings eliminating the necessity of establishing a Fault current baseline and periodically performing short-circuit studies. This option provides the entity the flexibility to choose an interval of up to six calendar years for performing the Protection System settings review.

- (Option 3) A combination of the above.

  As a third option, an entity has the flexibilityto apply a combination of the two methodologies based on criteria such as voltage level or Protection System applications. For example, an entity may choose the periodic Protection System review (option 2) and review its Facilities operated above 300 kV on a six year interval, while choosing to use the Fault current review (option 1) for its Facilities operated below 300 kV and periodically compare available Fault currents against the Fault current baseline.

Part 1.4 A quality review of the Protection System settings prior to implementation.

A quality review of the Protection System settings prior to implementation reduces the possibility of human error being introduced into the development of the Protection System settings. A quality review is any systematic process of verifying that the developed settings meet the entity's specific requirements for Protection System performance. Peer reviews, automated checking programs, and entity-developed review procedures are all examples of quality reviews.

Part 1.5 For new or revised Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities, (Transmission Owners, Generator Owners, and Distribution Providers), procedures to:

Part 1.5 addresses the coordination of Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities. Communications among these entities is essential so potential coordination issues can be identified and addressed prior to implementation of any proposed Protection System changes.

> **1.5.1** Communicate the proposed Protection System settings with the other functional entities.

Part 1.5.1 mandates entities have a procedure to communicate proposed Protection System settings with other entities. These communications ensure that the other entities have the necessary information to review the settings and determine if there are any coordination issues.

> **1.5.2** Review proposed Protection System settings provided by other functional entities, and respond regarding the proposed settings. The response should identify any coordination issue(s) or affirm that no coordination issue(s) were identified.

Part 1.5.2 mandates the entity receiving proposed Protection System settings have a procedure to review the settings and respond to the entity that initiated the proposed changes. This ensures that the proposed settings are reviewed and the initiating entity receives a response. The response must include any identified coordination issues, or affirm that no issues were identified.

> **1.5.3** Verify that any identified coordination issue(s) associated with proposed Protection System settings for the associated Elements are addressed prior to implementation.

Part 1.5.3 mandates the entity have a procedure to verify that any identified coordination issue(s) associated with the proposed Protection System settings are addressed prior to implementation. This ensures any potential impact to BES reliability are minimized.

The drafting team recognizes there could be instances where coordination issues are identified that pose minimum risk to the reliability of the BES, and the entities, therefore, agree to allow the unmitigated issue to remain. It is also recognized that coordination issues identified during a project may not be immediately resolved if the resolution involves additional system modifications not identified in the initial project scope. The drafting team also recognizes there are situations where entities' protection philosophies differ but they can agree that there were no identified coordination issues.

Requirement R2:

The requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall implement the process established in accordance with Requirement R1.

This requirement directs the applicable entities to implement the process established in Requirement R1. Implementing each of the elements of the process ensures a consistent approach to the development of accurate Protection System settings, minimizes the possibility of introducing errors, and maximizes the likelihood of maintaining a coordinated Protection System.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes was moved to this section.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Periodic Review of EOP-004-2 – Event Reporting

Project 2015-02 Emergency Operations Periodic Review

Introduction

NERC is required to conduct a periodic review of each NERC Reliability Standard at least once every ten years, or once every five years for Reliability Standards approved by the American National Standards Institute as an American National Standard.[1] The Reliability Standard identified below has been included in the current cycle of periodic reviews. The Review Team is instructed to use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be: (1) reaffirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) retired. If the Review Team recommends a revision to the Reliability Standard, it must also develop a draft Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision.

A completed Periodic Review Template and any associated documentation should be submitted by email to the NERC Standards Developer assigned to the project.

Applicable Reliability Standard: EOP-004-2 – Event Reporting
Review Team Members (include name and organization): 1. David McRee (Chair), Duke Energy 2. Connie Lowe (Vice Chair), Dominion Resources Services, Inc. 3. Mark Atkins, VELCO 4. Matthew Beilfuss, We Energies 5. Richard Cobb, MISO 6. Bobby Crump, Luminant Generation Company 7. Charles Jen, CenterPoint Energy Houston Electric 8. David Mahlmann, New York ISO 9. Robert Staton, Xcel Energy NERC standard developers: Laura Anderson and Steve Crutchfield
Date Review Completed: March 24, 2015

[1] NERC Standard Processes Manual 45 (2013), posted at http://www.nerc.com/pa/Stand/Documents/Appendix_3A_StandardsProcessesManual.pdf.

Background Information ***(to be completed initially by NERC staff)***

1. Are there any outstanding Federal Energy Regulatory Commission directives associated with the Reliability Standard? (If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)

   ☐ Yes

   ☒ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an Interpretation (outstanding, in progress, or approved), Compliance Application Notice (CAN) (outstanding, in progress, or approved), or an outstanding submission to NERC's Issues Database? (If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or stakeholder-identified issue(s) contained in the NERC Issues Database that apply to the Reliability Standard.)

   ☐ Yes

   ☒ No

3. Is the Reliability Standard one of the most violated Reliability Standards? If so, does the root cause of the frequent violation appear to be a lack of clarity in the language?

   ☐ Yes

   ☒ No

   Please explain:

4. Does the Reliability Standard need to be modified or converted to the results-based standard (RBS) format as outlined in *Attachment 1: Results-Based Standards*? Note that this analysis is two-fold and requires collaboration among NERC staff and the Review Team. First, does the *substance* of the Reliability Standard comport to the RBS principles described in Attachment 1? Second, does the *formatting* of the Reliability Standard need to be changed to comply with the RBS format used for new and revised Reliability Standards? If the answer to either part of this question is "Yes," the standard should be revised. In the comment field, please indicate what kind of revision will be necessary.

   ☐ Yes

   ☒ No

   Please explain:

Questions for the Subject Matter Expert (SME) Review Team

If NERC staff answered "Yes" to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide the SME review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above.

1. **Paragraph 81**: Does one or more of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? Use *Attachment 2: Paragraph 81 Criteria* to make this determination.

   ☐ Yes

   ☒ No

Please summarize your application of Paragraph 81 Criteria, if any:

It is suggested within the Independent Expert Review Project (IERP) to either retire Requirement R3 or, in the alternative, to combine Requirements R1 and R3. The EOP Periodic Review Team (PRT) *does not* recommend retiring Requirement R3. Requirement R3, while administrative, does support real-time operations as a function necessary to promote reliability.

Requirement R3 requires validation to ensure that the contact information, including phone numbers, is still accurate in the Operating Plan. During Emergency operations, operators should not be burdened with looking up contact information or having invalid phone numbers. Due to the nature of contact information changing, the EOP PRT recommends retaining Requirement R3 in EOP-004-2 to support up-to-date listings for use during emergency operations.

The EOP PRT does not support the recommendation contained in the IERP to combine Requirements R1 and R3. The EOP PRT recommends that Requirements R1 and R3 remain as separate requirements due to differing VRF levels (Requirement R1 is a low VRF level, whereas Requirement R3 is a high VRF level).

2. **Clarity:** If the Reliability Standard has an Interpretation, CAN, or issue associated with it, or is frequently violated because of ambiguity, it probably needs to be revised for clarity. Beyond these indicators, is there any reason to believe that the Reliability Standard should be modified to address a lack of clarity? Consider:

    a. Is this a Version 0 Reliability Standard?
    b. Does the Reliability Standard have obviously ambiguous language or language that requires performance that is not measurable?
    c. Are the requirements consistent with the purpose of the Reliability Standard?

    ☒ Yes

    ☐ No

Please summarize your assessment:

a. Following extensive discussion regarding the relationship between EOP-004-2 and the Department of Energy OE-417[2] report, the EOP PRT came to consensus that the relationship between the reporting requirements contained in the Standard and the Department of Energy OE-417 report is clear as written. EOP-004-2 is also applicable to jurisdiction outside of the United States which do not use the Department of Energy OE-417 report.

b. VSL for Requirement R2 –

   Add "recognition of" to the threshold of VSL table for Requirement R2 to provide the needed consistency between the requirement and the measure.

c. Attachment 1 - The EOP PRT recommends the future Standard Drafting Team (SDT) consider the following revisions to Attachment 1 for clarity regarding:

- Include additional information in the Guideline and Technical Basis regarding the good practice of physically and digitally surveying control houses following a breach.
- Add the phrase "Do not report theft unless it degrades normal operation of a Facility" criteria from 'Physical Threats to a Facility,' to 'Damage or Destruction of a Facility;' (add to third column of second row on Page 8 of the standard in Attachment 1).
- Review for revision "Entity with Reporting Responsibility" for proper application of "initiating entity" (Page 9 of Standard in Attachment 1).

[2] Department of Energy OE-417 Report, posted at http://www.oe.netl.doe.gov/oe417.aspx

- Generation loss/event type (from Page 10 of the Attachment): The EOP PRT reviewed, discussed, and came to consensus that the threshold of reporting is per Interconnection; and, therefore, suggests that the GOP be removed from reporting responsibility, eliminating duplicative reporting by the GOP and BA.

The EOP PRT recommends that the future SDT, in collaboration with NERC Compliance Assurance, revise the associated Reliability Standard Audit Worksheet (RSAW) based on any revisions made to this Standard.

The EOP PRT recommends that the future SDT review EOP-004-2 for grammar, punctuation, and syntax edit revisions.

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

☒ Yes

☐ No

Please explain:

The EOP PRT recommends review by the future SDT of the term "load" in EOP-004-2 and revise to "Load" if the future SDT determines "load" is intended to be the defined term "Load[3]," and to review the term for conflict with applicable entity (Load is not a physical end use device, but the existence of the capability to deliver electric energy – MW reduction).

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, Violation Risk Factors (VRF), and Violation Severity Levels (VSL)) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines? If you answered "No," please identify which elements require revision, and why:

☐ Yes

☒ No

EOP-004-2 – Section 1.2, Evidence Retention: The EOP PRT recommends that the future SDT review the evidence retention periods.

[3] NERC Glossary of Terms, posted at http://www.nerc.com/pa/stand/glossary%20of%20terms/glossary_of_terms.pdf

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard or consistency with other Reliability Standards? If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

   ☐ Yes
   ☒ No

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions, or other factors? If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

   ☒ Yes
   ☐ No

The EOP PRT recommends that the future SDT review the "Threshold for Reporting" column in Attachment 1 of EOP-004-2 for consistency in timeframe, MW values, and BES applicability threshold.

7. **Consideration of Generator Interconnection Facilities:** Is responsibility for generator interconnection Facilities appropriately accounted for in the Reliability Standard?

   ☒ Yes
   ☐ No

   Guiding Questions:

   If the Reliability Standard is applicable to GOs/GOPs, is there any ambiguity about the inclusion of generator interconnection Facilities? (If generation interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

   If the Reliability Standard is not applicable to GOs/GOPs, is there a reliability-related need for treating generator interconnection Facilities as transmission lines for the purposes of this Reliability Standard? (If so, GOs and GOPs that own or operate relevant generator interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

Recommendation

The answers to the questions above, along with a preliminary recommendation of the Review Team, will be posted for a 45-day comment period, and the comments will be publicly posted. The Review Team will review the comments to evaluate whether to modify the initial recommendation, and will document the final recommendation, which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the Review Team after its review and prior to posting the results of the review for industry comment):

- ☐ REAFFIRM
- ☒ REVISE
- ☐ RETIRE

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*: Please see above for the technical justification for revising this standard.

Preliminary Recommendation posted for industry comment (date): March 27, 2015

Final Recommendation (to be completed by the Review Team after it has reviewed industry comments on the preliminary recommendation):

- ☐ REAFFIRM *(This should only be checked if there are no outstanding directives, interpretations or issues identified by stakeholders.)*
- ☐ REVISE
- ☐ RETIRE

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Date submitted to NERC Staff:

Attachment 1: Results-Based Standards

The fourth question for NERC staff and the Review Team asks if the Reliability Standard needs to be converted to the results-based standards (RBS) format. The information below will be used by NERC staff and the Review Team in making this determination.

Transitioning the current body of standards into a clear and concise body of world-class standards will require a comprehensive application of the RBS concept. RBS concepts employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures, and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

Accordingly, the Review Team shall consider whether the Reliability Standard contains results-based requirements with sufficient clarity to hold entities accountable without being overly prescriptive as to how a specific reliability outcome is to be achieved. The RBS concept, properly applied, addresses the clarity and effectiveness aspects of a standard.

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff and the Review Team should recommend that the Reliability Standard be revised or reformatted in accordance with the RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[4] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Periodic Review Template.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion); and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

[4] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect reliability of the bulk power system.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?
The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the periodic review. The exception would be a requirement, such as the Critical Information Protection (CIP) requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?

The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?

The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles

NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Periodic Review of EOP-005-2 – System Restoration from Blackstart Resources

Project 2015-02 Emergency Operations Periodic Review

Introduction

NERC is required to conduct a periodic review of each NERC Reliability Standard at least once every ten years, or once every five years for Reliability Standards approved by the American National Standards Institute as an American National Standard.[1] The Reliability Standard identified below has been included in the current cycle of periodic reviews. The Review Team is instructed to use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be: (1) reaffirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) retired. If the Review Team recommends a revision to the Reliability Standard, it must also develop a draft Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision.

A completed Periodic Review Template and any associated documentation should be submitted by email to the NERC Standards Developer assigned to the project.

Applicable Reliability Standard: EOP-005-2 – System Restoration from Blackstart Resources
Review Team Members (include name and organization): 1. David McRee (Chair), Duke Energy 2. Connie Lowe (Vice Chair), Dominion Resources Services, Inc. 3. Mark Atkins, VELCO 4. Matthew Beilfuss, We Energies 5. Richard Cobb, MISO 6. Bobby Crump, Luminant Generation Company 7. Charles Jen, CenterPoint Energy Houston Electric 8. David Mahlmann, New York ISO 9. Robert Staton, Xcel Energy NERC standard developers: Laura Anderson and Steve Crutchfield
Date Review Completed: March 24, 2015

[1] NERC Standard Processes Manual 45 (2013), posted at http://www.nerc.com/pa/Stand/Documents/Appendix_3A_StandardsProcessesManual.pdf.

Background Information *(to be completed initially by NERC staff)*

1. Are there any outstanding Federal Energy Regulatory Commission directives associated with the Reliability Standard? (If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)

   ☐ Yes

   ☒ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an Interpretation (outstanding, in progress, or approved), Compliance Application Notice (CAN) (outstanding, in progress, or approved), or an outstanding submission to NERC's Issues Database? (If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or stakeholder-identified issue(s) contained in the NERC Issues Database that apply to the Reliability Standard.)

   ☐ Yes

   ☒ No

3. Is the Reliability Standard one of the most violated Reliability Standards? If so, does the root cause of the frequent violation appear to be a lack of clarity in the language?

   ☐ Yes

   ☒ No

   Please explain:

4. Does the Reliability Standard need to be modified or converted to the results-based standard (RBS) format as outlined in *Attachment 1: Results-Based Standards*? Note that this analysis is two-fold and requires collaboration among NERC staff and the Review Team. First, does the *substance* of the Reliability Standard comport to the RBS principles described in Attachment 1? Second, does the *formatting* of the Reliability Standard need to be changed to comply with the RBS format used for new and revised Reliability Standards? If the answer to either part of this question is "Yes," the standard should be revised. In the comment field, please indicate what kind of revision will be necessary.

   ☒ Yes

   ☐ No

Please explain: EOP-005-2 – System Restoration from Blackstart Resources needs to be converted to the results-based standard (RBS) format as outlined in *Attachment 1: Results-Based Standards*.

Questions for the Subject Matter Expert (SME) Review Team

If NERC staff answered "Yes" to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide the SME review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above.

1. **Paragraph 81**: Does one or more of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? Use *Attachment 2: Paragraph 81 Criteria* to make this determination.

   ☒ Yes

   ☐ No

Please summarize your application of Paragraph 81 Criteria, if any:

Requirement R10: The EOP Periodic Review Team (PRT) recommends retirement of Requirement R10, and all of its subparts (requirement parts), as duplicative of proposed PER-005-2. The four identified tasks identified in Requirement R10, reviewed every year, provide for elements of the training; per P81 Criteria B7[2] this is redundant.

<u>The EOP PRT *does not* recommend retirement of the following requirements identified in the Independent Expert Review Project (IERP)</u>:

- IERP: Requirement R7 – The EOP PRT discussed the following possible scenario: if a Disturbance occurs and the TOP does nothing – Requirement R7 requires the TOP to *implement* the plan. The EOP PRT recommends that the future SDT consider revising Requirement R7 for consistency by using already-approved industry terminology, "Develop, maintain and implement," from Standards such as proposed EOP-011-1 and EOP-010-1 to replace the strict implementation requirement.
- IERP: The IERP determined Requirement R8 to be duplicative with EOP-005-2 Requirement 1.3. The EOP PRT does not find Requirement R8 to be duplicative with EOP-005-2 Requirement R1.3. EOP-005-2 R1.3 is a requirement that requires the following: (a) the TOP plan requires Reliability Coordinator approval for resynchronizing, and (b) that when the event occurs, that portion of the plan be adhered to. The EOP PRT recommends that the future SDT consider

[2] NERC Periodic Review Template: Attachment 2: Paragraph 81 Criteria

revising Requirement R7 for consistency by using already-approved industry terminology, "Develop, maintain and implement," from Standards, such as proposed EOP-011-1 and EOP-010-1. This language captures the implementation aspect of Requirement R8, and adds the requirement for Reliability Coordinator approval of the plan, as required under Requirement R1.3.

- IERP: The IERP determined Requirement R12 to be duplicative with PER-005-1 Requirement R3. The EOP PRT does not recommend retirement of EOP-005-2 Requirement R12. Requirement R12 is not a training requirement, it is a testing requirement ("drill, exercise, or simulation"), which determines the necessity for personnel training under PER-005-1 Requirement R3.

2. **Clarity:** If the Reliability Standard has an Interpretation, CAN, or issue associated with it, or is frequently violated because of ambiguity, it probably needs to be revised for clarity. Beyond these indicators, is there any reason to believe that the Reliability Standard should be modified to address a lack of clarity? Consider:

    a. Is this a Version 0 Reliability Standard?
    b. Does the Reliability Standard have obviously ambiguous language or language that requires performance that is not measurable?
    c. Are the requirements consistent with the purpose of the Reliability Standard?

    ☒ Yes

    ☐ No

    a. The EOP PRT recommends Requirement R4 be reviewed for clarity regarding the application of when the 90 calendar days applies and update the associated Measure, if applicable.

    b. The EOP PRT recommends that the future SDT look at Requirement R5 and its associated Measure for consideration of the use of "Implementation Date" versus "Effective Date" or "Approval Date" and consider if the plan should contain the specific term "Implementation Date."

    c. The EOP PRT recommends that the future SDT reword Measure M5 for clarity:

    M5. Each Transmission Operator shall have documentation that it has made the latest Reliability Coordinator approved copy of its restoration plan, in electronic or hardcopy format, available in its primary and backup control rooms and its System Operators prior to its implementation date in accordance with Requirement R5.

d. The EOP PRT recommends that the future SDT review the use of the terms "plans" and "procedures" used throughout the standard for consistency.

e. The EOP PRT recommends the future SDT add a Rationale Box to clarify Requirement R6 and the use of the phrase "dynamic simulations". In addition, the EOP PRT recommends that the future SDT verify that the RSAW is appropriate to capture the intent of the requirement.

R6. Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed every five years at a minimum. Such analysis, simulations or testing shall verify: *[Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]*
Proposed Rationale Box: Dynamic simulations should simulate your frequency and voltage response beyond the transient period of time. It is the intent of the (future) EOP SDT that the simulation provides for the feedback of the System performance as generation and Load are added.

f. The EOP PRT recommends that the future SDT review the language of Requirement R7 for clarity, and update the associated Measure:

R7. Following a Disturbance in which one or more areas of the BES shuts down and the use of ~~Blackstart Resources~~ the restoration plan, pursuant to Requirement R1, is required to restore the shut down area to service, each affected Transmission Operator shall implement its restoration plan. If the restoration plan cannot be executed as expected the Transmission Operator shall utilize its restoration strategies to facilitate restoration. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*

g. The EOP PRT recommends the future SDT review the language of Requirement R8 for clarity, and update the associated Measure:

R8: Following a Disturbance in which one or more areas of the BES shuts down and the use of ~~Blackstart Resources~~ the restoration plan, pursuant to Requirement R1, is required to restore the shut down area to service, the Transmission Operator shall resynchronize area(s) with neighboring Transmission Operator area(s) only with the authorization of the Reliability Coordinator or in accordance with the established procedures of the Reliability Coordinator. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*

h. The EOP PRT recommends a review of the associated Reliability Standard Audit Worksheet (RSAW), in collaboration with NERC Compliance Assurance, to ensure any changes to the Standard are captured.

i. The EOP PRT recommends that the future SDT review EOP-005-2 for grammar, punctuation, and syntax edit revisions.

j. The EOP PRT has reviewed the Federal Energy Regulatory Commission (Commission) request to review in EOP-005, System Restoration, Commission Order 749, Paragraphs 24 and 18:

Paragraph 18
"Requirement R11 of EOP-005-2 requires that a minimum of two hours of system restoration training be provided every two years to field switching personnel performing "unique tasks" associated with the transmission operator's restoration plan. In the NOPR, the Commission expressed concern that the applicable entities may not understand what the term "unique tasks" means. We requested comment on what is intended by that term and on whether guidance should be provided to the transmission operators, transmission owners, and distribution providers who are responsible for providing training. In addition, the NOPR sought comment as to whether the unique tasks should be identified in each transmission operator's restoration plan."

Paragraph 24
"Both EEI and APPA recognize potential benefit in the development of further guidance as to the term "unique tasks," and BPA is uncertain as to the meaning of the term and consequently unsure as to how to demonstrate compliance with its training obligation. NERC, in its comments about the term, states that it "could promote the development of a guideline to aid registered entities in complying with Requirement R11." The Commission notes that this Reliability Standard will not become effective for at least 24 months, during which time ambiguities in language or differences of opinion among affected entities may be resolved in practical ways. Once the Standard is effective, if industry determines that ambiguity with the term arises, it would be appropriate for NERC to consider its proposal to develop a guideline to aid entities in their compliance obligations."

The EOP PRT is not aware of any industry confusion regarding the application of "unique tasks." The EOP PRT recommends that the future SDT review any reported industry confusion regarding the application of "unique tasks" that may be reported subsequent to the close of the Periodic Review of Emergency Operations, Project 2015-02.

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

☐ Yes

☒ No

Please explain:

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, Violation Risk Factors (VRF), and Violation Severity Levels (VSL)) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines? If you answered "No," please identify which elements require revision, and why:

   ☐ Yes
   ☒ No

EOP-005-2 – Section 1.4, Evidence Retention: Recommend the future drafting team review the evidence retention periods.

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard or consistency with other Reliability Standards? If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

   ☐ Yes
   ☒ No

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions, or other factors? If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

   ☐ Yes
   ☒ No

7. **Consideration of Generator Interconnection Facilities:** Is responsibility for generator interconnection Facilities appropriately accounted for in the Reliability Standard?

   ☒ Yes
   ☐ No

   Guiding Questions:

If the Reliability Standard is applicable to GOs/GOPs, is there any ambiguity about the inclusion of generator interconnection Facilities? (If generation interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

If the Reliability Standard is not applicable to GOs/GOPs, is there a reliability-related need for treating generator interconnection Facilities as transmission lines for the purposes of this Reliability Standard? (If so, GOs and GOPs that own or operate relevant generator interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

Recommendation

The answers to the questions above, along with a preliminary recommendation of the Review Team, will be posted for a 45-day comment period, and the comments will be publicly posted. The Review Team will review the comments to evaluate whether to modify the initial recommendation, and will document the final recommendation, which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the Review Team after its review and prior to posting the results of the review for industry comment):

- ☐ REAFFIRM
- ☒ REVISE
- ☒ RETIRE - Requirement R10: The EOP PRT recommends retirement of Requirement R10, and all of its subparts (requirement parts), as duplicative of Proposed PER-005-2. The four identified tasks identified in Requirement R10, reviewed every year, provides for elements of the training; per P81 Criterion B7 – redundant.

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*: Please see above for the technical justification for revising this standard.

Preliminary Recommendation posted for industry comment (date): March 27, 2015

Final Recommendation (to be completed by the Review Team after it has reviewed industry comments on the preliminary recommendation):

- ☐ REAFFIRM *(This should only be checked if there are no outstanding directives, interpretations or issues identified by stakeholders.)*
- ☐ REVISE
- ☐ RETIRE

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Date submitted to NERC Staff:

Attachment 1: Results-Based Standards

The fourth question for NERC staff and the Review Team asks if the Reliability Standard needs to be converted to the results-based standards (RBS) format. The information below will be used by NERC staff and the Review Team in making this determination.

Transitioning the current body of standards into a clear and concise body of world-class standards will require a comprehensive application of the RBS concept. RBS concepts employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures, and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

Accordingly, the Review Team shall consider whether the Reliability Standard contains results-based requirements with sufficient clarity to hold entities accountable without being overly prescriptive as to how a specific reliability outcome is to be achieved. The RBS concept, properly applied, addresses the clarity and effectiveness aspects of a standard.

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff and the Review Team should recommend that the Reliability Standard be revised or reformatted in accordance with the RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[3] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Periodic Review Template.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion); and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

[3] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect reliability of the bulk power system.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?
The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the periodic review. The exception would be a requirement, such as the Critical Information Protection (CIP) requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?

The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?

The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles

NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

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Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Periodic Review of EOP-006-2 – System Restoration Coordination

Project 2015-02 Emergency Operations Periodic Review

Introduction

NERC is required to conduct a periodic review of each NERC Reliability Standard at least once every ten years, or once every five years for Reliability Standards approved by the American National Standards Institute as an American National Standard.[1] The Reliability Standard identified below has been included in the current cycle of periodic reviews. The Review Team is instructed to use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be: (1) reaffirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) retired. If the Review Team recommends a revision to the Reliability Standard, it must also develop a draft Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision.

A completed Periodic Review Template and any associated documentation should be submitted by email to the NERC Standards Developer assigned to the project.

Applicable Reliability Standard: EOP-006-2 – System Restoration Coordination
Review Team Members (include name and organization): 1. David McRee (Chair), Duke Energy 2. Connie Lowe (Vice Chair), Dominion Resources Services, Inc. 3. Mark Atkins, VELCO 4. Matthew Beilfuss, We Energies 5. Richard Cobb, MISO 6. Bobby Crump, Luminant Generation Company 7. Charles Jen, CenterPoint Energy Houston Electric 8. David Mahlmann, New York ISO 9. Robert Staton, Xcel Energy NERC standard developers: Laura Anderson and Steve Crutchfield
Date Review Completed: March 24, 2015

[1] NERC Standard Processes Manual 45 (2013), posted at http://www.nerc.com/pa/Stand/Documents/Appendix_3A_StandardsProcessesManual.pdf.

Background Information ***(to be completed initially by NERC staff)***

1. Are there any outstanding Federal Energy Regulatory Commission directives associated with the Reliability Standard? (If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)

   ☐ Yes

   ☒ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an Interpretation (outstanding, in progress, or approved), Compliance Application Notice (CAN) (outstanding, in progress, or approved), or an outstanding submission to NERC's Issues Database? (If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or stakeholder-identified issue(s) contained in the NERC Issues Database that apply to the Reliability Standard.)

   ☐ Yes

   ☒ No

3. Is the Reliability Standard one of the most violated Reliability Standards? If so, does the root cause of the frequent violation appear to be a lack of clarity in the language?

   ☐ Yes

   ☒ No

   Please explain:

4. Does the Reliability Standard need to be modified or converted to the results-based standard (RBS) format as outlined in *Attachment 1: Results-Based Standards*? Note that this analysis is two-fold and requires collaboration among NERC staff and the Review Team. First, does the *substance* of the Reliability Standard comport to the RBS principles described in Attachment 1? Second, does the *formatting* of the Reliability Standard need to be changed to comply with the RBS format used for new and revised Reliability Standards? If the answer to either part of this question is "Yes," the standard should be revised. In the comment field, please indicate what kind of revision will be necessary.

   ☒ Yes

   ☐ No

Please explain:

EOP-006-2 – System Restoration Coordination needs to be converted to the results-based standard (RBS) format as outlined in *Attachment 1: Results-Based Standards*

Questions for the Subject Matter Expert (SME) Review Team

If NERC staff answered "Yes" to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide the SME review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above.

1. **Paragraph 81**: Does one or more of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? Use *Attachment 2: Paragraph 81 Criteria* to make this determination.

   ☒ Yes

   ☐ No

   Please summarize your application of Paragraph 81 Criteria, if any:

The EOP Periodic Review Team (PRT) *does not* recommend retiring the following requirements identified in the Independent Expert Review Project (IERP):

- IERP: Requirement R7– Accountability to implement the plan. The EOP PRT recommends that the future SDT consider revision for consistency by using the already-approved industry terminology, "Develop, maintain and implement," from Standards such as proposed EOP-011-1 and EOP-010-1.
- IERP: Requirement R8 – Requirement R8 requires only implementing a very specific element of the restoration plan; i.e., resynchronizing islanded areas. The EOP PRT recommends that the future SDT consider revising Requirement R8 to capture "Develop, maintain and implement" (similar to the proposed EOP-011-1) so that all pertinent aspects of the plan are implemented as system conditions warrant. The requirement to use the plan would be captured under the phrase "Develop, maintain and implement."
- Requirement R10 – Requirement R10 addresses exercises and drills by using the terms "drill, exercise, or simulation", which are methods of testing and validating implementation of the plan. The GOP has a drill requirement in EOP-005-2, which is not captured in PER-005-1.

The EOP PRT *does* recommend retiring the following requirements identified in the IERP:

- Requirement Parts R1.2, R1.3, and R1.4 should be retired under Paragraph 81, Criterion B7[2], as redundant with Requirement R1, Part R1.5.

[2] NERC Periodic Review Template: Attachment 2: Paragraph 81 Criteria

- Requirement R9 – Requirement R9 is duplicative with PER-005-2 Requirement R1, and should be retired under Paragraph 81, Criterion B7, as redundant. PER-005-2 Requirement R1 requires a listing of all of the tasks the System Operator is required to perform and requires the Reliability Coordinator to establish a training program for its BES entity-specific reliability related tasks.

2. **Clarity:** If the Reliability Standard has an Interpretation, CAN, or issue associated with it, or is frequently violated because of ambiguity, it probably needs to be revised for clarity. Beyond these indicators, is there any reason to believe that the Reliability Standard should be modified to address a lack of clarity? Consider:

   a. Is this a Version 0 Reliability Standard?
   b. Does the Reliability Standard have obviously ambiguous language or language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?

   ☒ Yes

   ☐ No

   Please summarize your assessment:

   a. For clarity, the EOP PRT recommends revision to Requirement R1.5 and its associated Measure:

      R1.5. Criteria and conditions for reestablishing interconnections with other Transmission Operators within its Reliability Coordinator Area, with adjacent Transmission Operators in other Reliability Coordinator Areas, and with ~~other~~ adjacent Reliability Coordinators.

   b. The EOP PRT recommends the future SDT revise EOP-006-2 to remove Requirement R1.9, as this is an unnecessary action.

   c. For clarity, the EOP PRT recommends revision to Requirement R7 and its associated Measure:

      R7 Each Reliability Coordinator shall, pursuant to the conditions addressed in Requirement R1, execute its restoration plan. ~~work with its affected Generator Operators (correct comma strikeout in the standard) and Transmission Operators as well as neighboring Reliability Coordinators to monitor restoration progress, coordinate restoration, and take actions to restore the BES frequency within acceptable operating limits.~~ If the restoration plan cannot be

executed ~~completed~~ as expected, the Reliability Coordinator shall utilize its restoration plan strategies to facilitate System restoration.

d. The EOP PRT recommends that the future SDT, in collaboration with NERC Compliance Assurance, revise the associated Reliability Standard Audit Worksheet (RSAW) based on any revisions made to this Standard.

e. The EOP PRT recommends that the future SDT review EOP-006-2 for grammar, punctuation, and syntax edit revisions.

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

☐ Yes
☒ No

Please explain:

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, Violation Risk Factors (VRF), and Violation Severity Levels (VSL)) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines? If you answered "No," please identify which elements require revision, and why:

☒ Yes
☐ No

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard or consistency with other Reliability Standards? If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

☐ Yes
☒ No

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions, or other factors? If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

☐ Yes

☒ No

7. **Consideration of Generator Interconnection Facilities:** Is responsibility for generator interconnection Facilities appropriately accounted for in the Reliability Standard?

☒ Yes

☐ No

Guiding Questions:

If the Reliability Standard is applicable to GOs/GOPs, is there any ambiguity about the inclusion of generator interconnection Facilities? (If generation interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

If the Reliability Standard is not applicable to GOs/GOPs, is there a reliability-related need for treating generator interconnection Facilities as transmission lines for the purposes of this Reliability Standard? (If so, GOs and GOPs that own or operate relevant generator interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

Recommendation

The answers to the questions above, along with a preliminary recommendation of the Review Team, will be posted for a 45-day comment period, and the comments will be publicly posted. The Review Team will review the comments to evaluate whether to modify the initial recommendation, and will document the final recommendation, which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the Review Team after its review and prior to posting the results of the review for industry comment):

☐ REAFFIRM

☒ REVISE

☒ RETIRE – Requirement subparts (requirement parts) R1.2, R1.3, and R1.4 should be retired under Paragraph 81, Criterion B7, as redundant with Requirement R1.5. Requirement R9 is duplicative with PER-005-2 Requirement R1, retire under Paragraph 81, Criterion B7, as redundant.

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*: Please see above for the technical justification for revising this standard.

Preliminary Recommendation posted for industry comment (date): March 27, 2015

Final Recommendation (to be completed by the Review Team after it has reviewed industry comments on the preliminary recommendation):

☐ REAFFIRM *(This should only be checked if there are no outstanding directives, interpretations or issues identified by stakeholders.)*

☐ REVISE

☐ RETIRE

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Date submitted to NERC Staff:

Attachment 1: Results-Based Standards

The fourth question for NERC staff and the Review Team asks if the Reliability Standard needs to be converted to the results-based standards (RBS) format. The information below will be used by NERC staff and the Review Team in making this determination.

Transitioning the current body of standards into a clear and concise body of world-class standards will require a comprehensive application of the RBS concept. RBS concepts employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures, and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

Accordingly, the Review Team shall consider whether the Reliability Standard contains results-based requirements with sufficient clarity to hold entities accountable without being overly prescriptive as to how a specific reliability outcome is to be achieved. The RBS concept, properly applied, addresses the clarity and effectiveness aspects of a standard.

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff and the Review Team should recommend that the Reliability Standard be revised or reformatted in accordance with the RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[3] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Periodic Review Template.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion); and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

[3] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect reliability of the bulk power system.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?
The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the periodic review. The exception would be a requirement, such as the Critical Information Protection (CIP) requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?

The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?

The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles

NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Periodic Review of EOP-008-1 – Loss of Control Center Functionality

Project 2015-02 Emergency Operations Periodic Review

Introduction

NERC is required to conduct a periodic review of each NERC Reliability Standard at least once every ten years, or once every five years for Reliability Standards approved by the American National Standards Institute as an American National Standard.[1] The Reliability Standard identified below has been included in the current cycle of periodic reviews. The Review Team is instructed to use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be: (1) reaffirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) retired. If the Review Team recommends a revision to the Reliability Standard, it must also develop a draft Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision.

A completed Periodic Review Template and any associated documentation should be submitted by email to the NERC Standards Developer assigned to the project.

Applicable Reliability Standard: EOP-008-1 – Loss of Control Center Functionality
Review Team Members (include name and organization): 1. David McRee (Chair), Duke Energy 2. Connie Lowe (Vice Chair), Dominion Resources Services, Inc. 3. Mark Atkins, VELCO 4. Matthew Beilfuss, We Energies 5. Richard Cobb, MISO 6. Bobby Crump, Luminant Generation Company 7. Charles Jen, CenterPoint Energy Houston Electric 8. David Mahlmann, New York ISO 9. Robert Staton, Xcel Energy NERC standard developers: Laura Anderson and Steve Crutchfield
Date Review Completed: March 24, 2015

[1] NERC Standard Processes Manual 45 (2013), posted at http://www.nerc.com/pa/Stand/Documents/Appendix_3A_StandardsProcessesManual.pdf.

Background Information *(to be completed initially by NERC staff)*

1. Are there any outstanding Federal Energy Regulatory Commission directives associated with the Reliability Standard? (If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)

   ☐ Yes

   ☒ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an Interpretation (outstanding, in progress, or approved), Compliance Application Notice (CAN) (outstanding, in progress, or approved), or an outstanding submission to NERC's Issues Database? (If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or stakeholder-identified issue(s) contained in the NERC Issues Database that apply to the Reliability Standard.)

   ☐ Yes

   ☒ No

3. Is the Reliability Standard one of the most violated Reliability Standards? If so, does the root cause of the frequent violation appear to be a lack of clarity in the language?

   ☐ Yes

   ☒ No

   Please explain:

4. Does the Reliability Standard need to be modified or converted to the results-based standard (RBS) format as outlined in *Attachment 1: Results-Based Standards*? Note that this analysis is two-fold and requires collaboration among NERC staff and the Review Team. First, does the *substance* of the Reliability Standard comport to the RBS principles described in Attachment 1? Second, does the *formatting* of the Reliability Standard need to be changed to comply with the RBS format used for new and revised Reliability Standards? If the answer to either part of this question is "Yes," the standard should be revised. In the comment field, please indicate what kind of revision will be necessary.

   ☒ Yes

   ☐ No

Please explain:

EOP-008-1 – Loss of Control Center Functionality needs to be converted to the results-based standard (RBS) format as outlined in *Attachment 1: Results-Based Standards*.

Questions for the Subject Matter Expert (SME) Review Team

If NERC staff answered "Yes" to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide the SME review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above.

1. **Paragraph 81**: Does one or more of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? Use *Attachment 2: Paragraph 81 Criteria* to make this determination.

   ☐ Yes

   ☒ No

   Please summarize your application of Paragraph 81 Criteria, if any:

2. **Clarity:** If the Reliability Standard has an Interpretation, CAN, or issue associated with it, or is frequently violated because of ambiguity, it probably needs to be revised for clarity. Beyond these indicators, is there any reason to believe that the Reliability Standard should be modified to address a lack of clarity? Consider:

   a. Is this a Version 0 Reliability Standard?
   b. Does the Reliability Standard have obviously ambiguous language or language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?

   ☒ Yes

   ☐ No

Please summarize your assessment:

a. The EOP PRT recommends that the future SDT revise Requirement R1, Part 1.1. and the associated Measure to provide clarity to the intended timeframe to restore primary control center functionality:

   1.1 The location and method of implementation for providing backup functionality ~~for the time it takes to restore the primary control center functionality~~.

b. The EOP PRT recommends that the future SDT, in collaboration with NERC Compliance Assurance, revise the associated Reliability Standard Audit Worksheet (RSAW) based on any revisions made to this Standard.

c. The EOP PRT recommends that the future SDT review EOP-008-1 for grammar, punctuation, and syntax edit revisions.

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

☐ Yes
☒ No

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, Violation Risk Factors (VRF), and Violation Severity Levels (VSL)) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines? If you answered "No," please identify which elements require revision, and why:

☒ Yes
☐ No

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard or consistency with other Reliability Standards? If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

☐ Yes
☒ No

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions, or other factors? If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

   ☐ Yes

   ☒ No

7. **Consideration of Generator Interconnection Facilities:** Is responsibility for generator interconnection Facilities appropriately accounted for in the Reliability Standard?

   ☒ Yes

   ☐ No

   Guiding Questions:

   If the Reliability Standard is applicable to GOs/GOPs, is there any ambiguity about the inclusion of generator interconnection Facilities? (If generation interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

   If the Reliability Standard is not applicable to GOs/GOPs, is there a reliability-related need for treating generator interconnection Facilities as transmission lines for the purposes of this Reliability Standard? (If so, GOs and GOPs that own or operate relevant generator interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

Recommendation

The answers to the questions above, along with a preliminary recommendation of the Review Team, will be posted for a 45-day comment period, and the comments will be publicly posted. The Review Team will review the comments to evaluate whether to modify the initial recommendation, and will document the final recommendation, which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the Review Team after its review and prior to posting the results of the review for industry comment):

- ☐ REAFFIRM
- ☒ REVISE
- ☐ RETIRE

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*: Please see above for the technical justification for revising this standard.

Preliminary Recommendation posted for industry comment (date): March 27, 2015

Final Recommendation (to be completed by the Review Team after it has reviewed industry comments on the preliminary recommendation):

- ☐ REAFFIRM *(This should only be checked if there are no outstanding directives, interpretations or issues identified by stakeholders.)*
- ☐ REVISE
- ☐ RETIRE

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Date submitted to NERC Staff:

Attachment 1: Results-Based Standards

The fourth question for NERC staff and the Review Team asks if the Reliability Standard needs to be converted to the results-based standards (RBS) format. The information below will be used by NERC staff and the Review Team in making this determination.

Transitioning the current body of standards into a clear and concise body of world-class standards will require a comprehensive application of the RBS concept. RBS concepts employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures, and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

Accordingly, the Review Team shall consider whether the Reliability Standard contains results-based requirements with sufficient clarity to hold entities accountable without being overly prescriptive as to how a specific reliability outcome is to be achieved. The RBS concept, properly applied, addresses the clarity and effectiveness aspects of a standard.

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff and the Review Team should recommend that the Reliability Standard be revised or reformatted in accordance with the RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[2] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Periodic Review Template.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion); and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

[2] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect reliability of the bulk power system.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?
The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the periodic review. The exception would be a requirement, such as the Critical Information Protection (CIP) requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?

The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?

The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles

NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of “Ballot Periods” column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
1	Project 2007-24	Request for Interpretation - TPL-002 and TPL-003 - Ameren_in	Initial Ballot	4/25/2008	5/7/2008	Quorum: 82.61% Approval: 80.73%			
2	Project 2007-26	Request for Interpretation - TPL-002 and TPL-003 - MISO_in	Initial Ballot	4/25/2008	5/7/2008	Quorum: 83.01% Approval: 79.89%			
3	Project 2008-04	FAC-010_FAC-011_FAC-014_Order_705_in	Initial Ballot	6/2/2008	6/11/2008	Quorum: 88.83% Approval: 95.43%			
4	Project 2008-07	Interpretation Request - EOP-002 - Brookfield_in	Initial Ballot	6/2/2008	6/11/2008	Quorum: 89.67% Approval: 76.47%			
5	Project 2008-04	FAC-010_FAC-011_FAC-014_Order_705_rc	Recirculation Ballot	6/13/2008	6/22/2008	Quorum: 89.36% Approval: 95.21%			
6	Project 2008-09	Request for Interpretation - EOP-001-0 - RECM_in	Initial Ballot	6/19/2008	7/2/2008	Quorum: 84.82% Approval: 85.79%			
7	Project 2007-24	Request for Interpretation - TPL-002 and TPL-003 - Ameren_rc	Recirculation Ballot	6/27/2008	7/7/2008	Quorum: 83.57% Approval: 79.13%			
8	Project 2007-26	Request for Interpretation - TPL-002 and TPL-003 - MISO_rc	Recirculation Ballot	6/27/2008	7/7/2008	Quorum: 83.98% Approval: 78.31%			
9	Pre-2006	IROL Standard - IRO-010_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 92.71% Approval: 88.40%			
10	Pre-2006	IROL Standard - IRO-009_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 92.63% Approval: 89.44%			
11	Pre-2006	IROL Standard - IRO-008_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 92.67% Approval: 91.71%			
12	Project 2006-07	ATC et al Standard - MOD-030_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.37% Approval: 56.56%			
13	Project 2006-07	ATC et al Standard - MOD-029_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.67% Approval: 92.62%			
14	Project 2006-07	ATC et al Standard - MOD-028_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.64% Approval: 79.47%			
15	Project 2006-07	ATC et al Standard - MOD-008_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.27% Approval: 80.44%			
16	Project 2006-07	ATC et al Standard - MOD-001_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.02% Approval: 75.97%			
17	Project 2008-10	Request for Interpretation - CIP-006-1 - Progress Energy_in	Initial Ballot	8/7/2008	8/16/2008	Quorum: 88.18% Approval: 21.52%			
18	Pre-2006	IROL Standard - IRO-008_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 93.72% Approval: 89.49%			
19	Pre-2006	IROL Standard - IRO-009_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 93.68% Approval: 86.53%			
20	Pre-2006	IROL Standard - IRO-010_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 93.75% Approval: 85.95%			
21	Project 2006-07	ATC et al Standards - MOD-001_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 94.87% Approval: 76.83%			
22	Project 2006-07	ATC et al Standard - MOD-008_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.15% Approval: 81.49%			
23	Project 2006-07	ATC et al Standard - MOD-028_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.54% Approval: 79.34%			
24	Project 2006-07	ATC et al Standard - MOD-029_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.56% Approval: 92.24%			
25	Project 2006-07	ATC et al Standard - MOD-030_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.24% Approval: 74.26%			
26	Project 2008-11	Request for Interpretation - VAR-002-1 - ICF Consulting_in	Initial Ballot	9/9/2008	9/17/2008	Quorum: 85.78% Approval: 90.37%			
27	Project 2006-07	ATC et al Standard - MOD-004_in	Initial Ballot	9/11/2008	9/21/2008	Quorum: 79.26% Approval: 66.29%			
28	Project 2007-14	Permanent Changes to CI Timing Tables_in	Initial Ballot	9/12/2008	9/22/2008	Quorum: 79.74% Approval: 100.00%			
29	Project 2008-07	Request for Interpretation - Brookfield Power - EOP-002_rb	Re-ballot	10/6/2008	10/24/2008	Quorum: 82.61% Approval: 74.67%			
30	Project 2008-13	Request for Interpretation - TOP-002-2 - Orlando Utilities Commission_in	Initial Ballot	10/21/2008	10/30/2008	Quorum: 83.33% Approval: 96.94%			
31	Project 2006-01	Project 2006-01 - PER-005-1_in	Initial Ballot	10/27/2008	11/5/2008	Quorum: 90.13% Approval: 82.47%			
32	Project 2006-09	Project 2006-09 - FAC-008-2 - Facility Ratings_in	Initial Ballot	10/27/2008	11/5/2008	Quorum: 89.13% Approval: 70.01%			

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33	Project 2006-07	ATC et al Standard - MOD-004 _rc	Recirculation Ballot	10/28/2008	11/6/2008	Quorum: 91.49% Approval: 83.71%			
34	Project 2006-07	Project 2006-07 (ATC) MOD-030-2 _in	Initial Ballot	12/1/2008	12/10/2008	Quorum: 83.77% Approval: 86.51%			
35	Project 2006-09	Project 2006-09 - FAC-008-2 - Facility Ratings _rc	Recirculation Ballot	12/10/2008	12/19/2008	Quorum: 93.04% Approval: 57.37%			
36	Project 2008-13	Request for Interpretation - TOP-002-2 - Orlando Utilities Commission _rc	Recirculation Ballot	12/10/2008	12/19/2008	Quorum: 87.62% Approval: 97.47%			
37	Project 2006-01	Project 2006-01 - PER-005-1 _rc	Recirculation Ballot	12/12/2008	12/22/2008	Quorum: 91.48% Approval: 80.63%			
38	Project 2008-15	Request for Interpretation - CIP-006-1a - US Army COE _in	Initial Ballot	1/5/2009	1/14/2009	Quorum: 91.15% Approval: 97.39%			
39	Project 2008-16	TOP-004-2 VSL Revisions _in	Initial Ballot	1/5/2009	1/14/2009	Quorum: 91.20% Approval: 93.93%			
40	Project 2008-11	Request for Interpretation - VAR-002-1 - ICF Consulting _rc	Recirculation Ballot	1/6/2009	1/15/2009	Quorum: 91.47% Approval: 91.21%			
41	Project 2006-07	Project 2006-07 (ATC) MOD-030-2 _rc	Recirculation Ballot	1/20/2009	1/29/2009	Quorum: 85.86% Approval: 86.39%			
42	Project 2008-16	TOP-004-2 VSL Revisions _rc	Recirculation Ballot	1/28/2009	2/6/2009	Quorum: 92.59% Approval: 96.06%			
43	Project 2008-15	Request for Interpretation - CIP-006-1a - US Army COE _rc	Recirculation Ballot	2/6/2009	2/16/2009	Quorum: 93.81% Approval: 99.12%			
44	Project 2008-09	Interpretation Request - EOP-001 - R1 - RECM _in	Initial Ballot	2/27/2009	3/9/2009	Quorum: 89.67% Approval: 89.03%			
45	Project 2008-18	Project 2008-18 Interpretation-Manitoba Hydro _in	Initial Ballot	3/19/2009	3/30/2009	Quorum: 89.78% Approval: 92.62%			
46	Project 2008-06	Project 2008-06: CIP-002-1-CIP-009-1 Revisions _in	Initial Ballot	4/1/2009	4/10/2009	Quorum: 91.90% Approval: 84.06%			
47	Project 2009-10	Project 2009-10 Interpretation - CMPWG - PRC-005-1 R1 _in	Initial Ballot	4/8/2009	4/17/2009	Quorum: 92.70% Approval: 92.71%			
48	Project 2006-03	Project 2006-03 EOP-001 EOP-005 EOP-006 System Restoration and Blackstart _in	Initial Ballot	4/14/2009	4/23/2009	Quorum: 89.81% Approval: 76.63%			
49	Project 2008-06	Project 2008-06: CIP-002-1-CIP-009-1 Revisions _rc	Recirculation Ballot	4/17/2009	4/27/2009	Quorum: 94.37% Approval: 88.32%			
50	Project 2008-18	Project 2008-18 Interpretation-Manitoba Hydro _rc	Recirculation Ballot	4/17/2009	4/27/2009	Quorum: 95.56% Approval: 92.81%			
51	Project 2009-11	Project 2009-11 Interpretation WECC Reliability Coordination Subcommittee IRO-10-1 _in	Initial Ballot	4/22/2009	5/1/2009	Quorum: 88.64% Approval: 84.77%			
52	Project 2006-03	Project 2006-03 EOP-001 EOP-005 EOP-006 System Restoration and Blackstart _rc	Recirculation Ballot	5/6/2009	5/18/2009	Quorum: 92.08% Approval: 75.39%			
53	Project 2009-15	Project 2009-15 Interpretation - NYISO - MOD-001-1, MOD-029-1 _in	initial Ballot	5/25/2009	6/4/2009	Quorum: 85.13% Approval: 82.10%			
54	Project 2009-11	Project 2009-11 Interpretation WECC Reliability Coordination Subcommittee IRO-10-1 _rc	Recirculation Ballot	5/26/2009	6/5/2009	Quorum: 90.45% Approval: 85.76%			
55	Project 2009-14	Project 2009-14 Interpretation - PacifiCorp - TPL-002-0a _in	Initial Ballot	6/1/2009	6/11/2009	Quorum: 87.10% Approval: 95.71%			
56	Project 2009-08	Project 2009-08 - Nuclear Plant Interface Coordination for Order 716 _in	Initial Ballot	6/12/2009	6/22/2009	Quorum: 81.72% Approval: 94.09%			
57	Project 2008-14	Project 2008-14 VSLs for CIP-002-1 through CIP-009-1 _in	Initial Ballot	6/15/2009	6/24/2009	Quorum: 87.23% Approval: 83.94%			
58	Project 2008-14	Project 2008-14 VSLs for CIP-002-1 through CIP-009-1 _rc	Recirculation Ballot	7/7/2009	7/16/2009	Quorum: 92.77% Approval: 84.96%			
59	Project 2009-15	Project 2009-15 Interpretation - NYISO - MOD-001-1, MOD-029-1 _rc	Recirculation Ballot	7/8/2009	7/17/2009	Quorum: 90.26% Approval: 82.25%			
60	Project 2009-08	Project 2009-08 - Nuclear Plant Interface Coordination for Order 716 _rc	Recirculation Ballot	7/10/2009	7/20/2009	Quorum: 87.10% Approval: 96.94%			
61	Project 2009-10	Project 2009-10 Interpretation - CMPWG - PRC-005-1 R1 _rc	Recirculation Ballot	7/24/2009	8/6/2009	Quorum: 95.26% Approval: 95.62%			
62	Project 2009-14	Project 2009-14 Interpretation - PacifiCorp - TPL-002-0a _rc	Recirculation Ballot	7/24/2009	8/6/2009	Quorum: 91.24% Approval: 98.85%			
63	Project 2007-23	Project 2007-23 TPL Violation Severity Levels _in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 85.71% Approval: 90.46%			
64	Project 2007-23	Project 2007-23 TOP Violation Severity Levels _in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.40% Approval: 89.14%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of “Ballot Periods” column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
65	Project 2007-23	Project 2007-23 PRC Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.32% Approval: 88.26%			
66	Project 2007-23	Project 2007-23 IRO Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.16% Approval: 90.15%			
67	Project 2007-23	Project 2007-23 INT, PER, and NUC Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 85.71% Approval: 88.63%			
68	Project 2007-23	Project 2007-23 FAC and MOD Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.64% Approval: 87.63%			
69	Project 2007-23	Project 2007-23 CIP, COM, and VAR Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.50% Approval: 85.78%			
70	Project 2007-23	Project 2007-23 BAL Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.28% Approval: 89.56%			
71	Project 2008-08	Project 2008-08 EOP Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 87.98% Approval: 87.31%			
72	Project 2009-17	Project 2009-17 Interpretation - Y-W Electric and Tri-State - PRC-004-1 and PRC-005-1_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 90.32% Approval: 62.15%			
73	RSDP V7	Reliability Standards Development Procedure - Version 7 - June 2009_rb	Re-ballot	7/27/2009	8/14/2009	Quorum: 84.65% Approval: 74.79%			
74	Project 2009-09	Project 2009-09 - Interpretation - Covanta Energy - CIP-001-1_in	Initial Ballot	8/6/2009	8/17/2009	Quorum: 84.68% Approval: 68.92%			
75	Project 2007-23	Project 2007-23 TPL Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 91.96% Approval: 89.28%			
76	Project 2007-23	Project 2007-23 BAL Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.04% Approval: 89.41%			
77	Project 2007-23	Project 2007-23 CIP, COM, and VAR Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.41% Approval: 84.64%			
78	Project 2007-23	Project 2007-23 FAC and MOD Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.67% Approval: 88.04%			
79	Project 2007-23	Project 2007-23 INT, PER, and NUC Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.17% Approval: 88.73%			
80	Project 2007-23	Project 2007-23 IRO Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 91.96% Approval: 90.77%			
81	Project 2007-23	Project 2007-23 PRC Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.31% Approval: 86.93%			
82	Project 2007-23	Project 2007-23 TOP Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.11% Approval: 88.26%			
83	Project 2008-08	Project 2008-08 EOP Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.70% Approval: 85.80%			
84	Order 706-B	Order 706-B Nuclear Implementation Plan_in	Initial Ballot	8/19/2009	8/28/2009	Quorum: 81.96% Approval: 97.37%			
85	Project 2008-07	Request for Interpretation - Brookfield Power - EOP-002_rc	Recirculation Ballot	8/20/2009	8/31/2009	Quorum: 86.96% Approval: 70.85%			
86	Project 2009-12	Project 2009-12 - Interpretation - PacifiCorp - CIP-005-1_in	Initial Ballot	8/27/2009	9/8/2009	Quorum: 84.68% Approval: 80.37%			
87	Project 2009-13	Project 2009-13 - Interpretation - PacifiCorp - CIP-006-1_in	Initial Ballot	8/27/2009	9/8/2009	Quorum: 84.92% Approval: 79.04%			
88	Project 2009-18	Project 2009-18 - Withdraw Three Midwest ISO Waivers_in	Initial Ballot	8/27/2009	9/8/2009	Quorum: 85.28% Approval: 99.62%			
89	Order 706-B	Order 706-B Nuclear Implementation Plan_rc	Recirculation Ballot	9/1/2009	9/10/2009	Quorum: 87.11% Approval: 97.18%			
90	RSDP V7	Reliability Standards Development Procedure - Version 7 - June 2009_rc	Recirculation Ballot	9/2/2009	9/14/2009	Quorum: 86.31% Approval: 76.09%			
91	Project 2008-06	Project 2008-06 Cyber Security (VRFs and VSLs for Version 2 CIP Standards)_in	Initial Ballot	9/10/2009	9/21/2009	Quorum: 87.45% Approval: 94.18%			
92	Project 2009-16	Project 2009-16 - Interpretation - WECC - CIP-007-1_in	Initial Ballot	9/9/2009	9/21/2009	Quorum: 85.31% Approval: 100.00%			
93	Project 2006-04	Project 2006-04 - Back-up Facilities - EOP-008-1_in	Initial Ballot	9/16/2009	9/28/2009	Quorum: 82.69% Approval: 72.86%			
94	Project 2009-09	Project 2009-09 - Interpretation - Covanta Energy - CIP-001-1_rc	Recirculation Ballot	9/29/2009	10/9/2009	Quorum: 89.92% Approval: 68.31%			
95	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-1 Revised R1 for Progress Energy	Initial Ballot	9/30/2009	10/12/2009	Quorum: 79.92% Approval: 74.47%			
96	Project 2009-12	Project 2009-12 - Interpretation - PacifiCorp - CIP-005-1_rc	Recirculation Ballot	10/16/2009	10/26/2009	Quorum: 86.29% Approval: 83.25%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of “Ballot Periods” column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
97	Project 2008-06	Project 2008-06 Cyber Security (VRFs and VSLs for Version 2 CIP Standards)_rc	Recirculation Ballot	11/2/2009	11/12/2009	Quorum: 88.70% Approval: 94.24%			
98	Project 2008-09	Project 2008-09 - Interpretation - RECM - Revision 2_in	Initial Ballot	11/5/2009	11/16/2009	Quorum: 85.97% Approval: 98.07%			
99	Project 2009-21	Project 2009-21 - Cyber Security Ninety-day Response_in	Initial Ballot	11/20/2009	11/30/2009	Quorum: 89.58% Approval: 88.07%			
100	Project 2009-17	Project 2009-17 - Interpretation Y-W Electric and Tri-State (Revision 1)_in	Initial Ballot	11/19/2009	12/7/2009	Quorum: 85.83% Approval: 58.91%			
101	Project 2009-20	Project 2009-20 - Interpretation - BAL-003-0 - Energy Mark, Inc._in	Initial Ballot	11/20/2009	12/7/2009	Quorum: 87.11% Approval: 93.40%			
102	Project 2009-21	Project 2009-21 - Cyber Security Ninety-day Response_rc	Recirculation Ballot	12/3/2009	12/14/2009	Quorum: 93.33% Approval: 85.55%			
103	Project 2009-23	Project 2009-23 - Interpretation - CIP-004-2 - U.S. Army Corps of Engineers_in	Initial Ballot	12/1/2009	12/14/2009	Quorum: 86.13% Approval: 72.11%			
104	Project 2009-13	Project 2009-13 - Interpretation - PacifiCorp - CIP-006-1_rc	Recirculation Ballot	12/11/2009	12/23/2009	Quorum: 90.08% Approval: 78.77%			
105	Project 2009-24	Project 2009-24 - Interpretation - FMPA - EOP-005-1_in	Initial Ballot	1/5/2010	1/15/2010	Quorum: 87.68% Approval: 17.79%			
106	Project 2009-25	Project 2009-25 - Interpretation - BPA - BAL-001-01.a and BAL-002-0_in	Initial Ballot	1/5/2010	1/15/2010	Quorum: 88.00% Approval: 34.28%			
107	Project 2009-26	Project 2009-26 - Interpretation - WECC - CIP-004-1_in	Initial Ballot	1/6/2010	1/19/2010	Quorum: 84.21% Approval: 42.24%			
108	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-2	Initial Ballot	1/12/2010	1/22/2010	Quorum: 89.16% Approval: 75.16%			
109	Project 2009-27	Project 2009-27 - Interpretation - TOP-002-2a for FMPAA_in	Initial Ballot	2/10/2010	2/22/2010	Quorum: 84.98% Approval: 90.82%			
110	Project 2009-28	Project 2009-28 - Interpretation - EOP-001-1 and EOP-001-2 for FMPP_in	Initial Ballot	2/10/2010	2/22/2010	Quorum: 87.36% Approval: 91.79%			
111	Project 2009-29	Project 2009-29 - Interpretation - TOP-002-2a for FMPP_in	Initial Ballot	2/11/2010	2/22/2010	Quorum: 84.34% Approval: 84.56%			
112	Project 2009-19	Project 2009-19 - Interpretation - BAL-002-0 Northwest Power Pool RSG_in	Initial Ballot	2/15/2010	2/26/2010	Quorum: 89.83% Approval: 48.60%			
113	Project 2009-20	Project 2009-20 - Interpretation - BAL-003-0 - Energy Mark, Inc._rc	Recirculation Ballot	2/16/2010	2/26/2010	Quorum: 92.44% Approval: 91.90%			
114	Project 2009-30	Project 2009-30 - Interpretation - PRC-001-1 for WPSC_in	Initial Ballot	2/15/2010	2/26/2010	Quorum: 89.51% Approval: 48.74%			
115	Project 2006-02	Project 2006-02 - Assess Transmission Future Needs - TPL-001-1_in	Initial Ballot	2/19/2010	3/1/2010	Quorum: 91.38% Approval: 35.36%			
116	Project 2009-31	Project 2009-31 - Interpretation - TOP-001-1 for FMPP_in	Initial Ballot	3/3/2010	3/16/2010	Quorum: 88.24% Approval: 98.27%			
117	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-2	Recirculation Ballot	3/8/2010	3/18/2010	Quorum: 93.71% Approval: 78.15%			
118	Project 2009-32	Project 2009-32 - Interpretation - EOP-003-1 for FMPP_rb	Re-ballot	3/10/2010	3/31/2010	Quorum: 91.37% Approval: 77.66%			
119	Project 2009-23	Project 2009-23 - Interpretation - CIP-004-2 - U.S. Army Corps of Engineers (Revision 1)_in	Initial Ballot	3/29/2010	4/8/2010	Quorum: 88.52% Approval: 63.43%			
120	Project 2008-09	Project 2008-09 - Interpretation - RECM - Revision 3_in	Initial Ballot	4/15/2010	4/26/2010	Quorum: 81.97% Approval: 98.64%			
121	SPM	Standards Process Manual Revisions_in	Initial Ballot	4/19/2010	4/29/2010	Quorum: 87.82% Approval: 80.48%			
122	Project 2009-17	Project 2009-17 - Interpretation Y-W Electric and Tri-State (Revision 2)_in	Initial Ballot	4/28/2010	5/10/2010	Quorum: 83.15% Approval: 74.55%			
123	SPM	Standards Process Manual Revisions_rc	Recirculation Ballot	4/30/2010	5/10/2010	Quorum: 93.73% Approval: 86.69%			
124	Project 2010-11	Project 2010-11 SAR for TPL Table 1 Order_in	Initial Ballot	5/17/2010	5/27/2010	Quorum: 84.41% Approval: 63.75%			
125	Project 2010-09	Project 2010-09: NUC Implementation Plans for CIP Version 2 and Version 3_in	Initial Ballot	5/19/2010	6/1/2010	Quorum: 84.83% Approval: 90.83%			
126	Project 2010-09	Project 2010-09: NUC Implementation Plans for CIP Version 2 and Version 3_rc	Recirculation Ballot	6/22/2010	7/2/2010	Quorum: 89.10% Approval: 87.24%			
127	Project 2006-04	Project 2006-04 - Backup Facilities - Revision 1_in	Initial Ballot	6/23/2010	7/6/2010	Quorum: 89.05% Approval: 79.45%			
128	Project 2006-08	Project 2006-08 - Reliability Coordination - Transmission Loading Relief_in	Initial Ballot	6/23/2010	7/6/2010	Quorum: 87.04% Approval: 84.98%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of “Ballot Periods” column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
129	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Initial Ballot	7/7/2010	7/17/2010	Quorum: 86.94% Approval: 43.13%			
130	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Initial Ballot	7/8/2010	7/17/2010	Quorum:91.12 % Approval: 22.91%			
131	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Non-binding Poll	7/8/2010	7/17/2010	Quorum: 86.00% Approval: 28.00%			
132	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: Protection System definition	Initial Ballot	7/8/2010	7/17/2010	Quorum: 87.85% Approval: 39.35%			
133	Project 2007-07	Project 2007-07 Vegetation Management: FAC-003-2	Initial Ballot	7/9/2010	7/19/2010	Quorum: 86.18% Approval: 65.93%			
134	Project 2006-04	Prokect 2006-04 - Backup Facilities - Revision 1_rc	Recirculation Ballot	7/16/2010	7/26/2010	Quorum: 93.43% Approval: 85.22%			
135	Project 2007-17	Project 2007-17 Protection System Maintenance: Protection System definition	Successive Ballot	7/23/2010	8/2/2010	Quorum: 94.70% Approval: 58.61%			
136	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Successive Ballot	7/24/2010	8/3/2010	Quorum: 92.99% Approval: 49.61%			
137	Project 2006-08	Project 2006-08 - Reliability Coordination - Transmission Loading Relief_rc	Recirculation Ballot	8/20/2010	8/30/2010	Quorum: 88.26% Approval: 93.93%			
138	Project 2007-04	Project 2007-04 - Certifying System Operators: PER-003-1	Initial Ballot	9/14/2010	9/24/2010	Quorum: 92.73% Approval: 79.17%			
139	Project 2010-15	Project 2010-15 - Urgent Action Revisions to CIP-005-3	Initial Ballot	9/17/2010	9/27/2010	Quorum: 96.46% Approval: 21.77%			
140	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Successive Ballot	9/24/2010	10/4/2010	Quorum: 85.71% Approval: 81.72%			
141	Project 2007-17	Project 2007-17 Protection System Maintenance: Protection System definition	Successive Ballot	10/2/2010	10/14/2010	Quorum: 84.11% Approval: 84.52%			
142	Project 2008-09	Project 2008-09 - Interpretation - RECM - Revision 3_rc	Recirculation Ballot	10/4/2010	10/14/2010	Quorum: 88.11% Approval: 99.14%			
143	Project 2009-28	Project 2009-28 - Interpretation - EOP-001-1 and EOP-001-2 for FMPP_rc	Recirculation Ballot	10/5/2010	10/15/2010	Quorum: 92.19% Approval: 94.78%			
144	Project 2009-27	Project 2009-27 - Interpretation - TOP-002-2a for FMPAA_rc	Recirculation Ballot	10/6/2010	10/16/2010	Quorum: 91.21% Approval: 93.44%			
145	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Recirculation Ballot	10/18/2010	10/28/2010	Quorum: 89.84% Approval: 84.67%			
146	Project 2008-06	Project 2008-06 Cyber Security 706 (Version 4 CIP Standards)_in	Initial Ballot	10/20/2010	11/3/2010	Quorum: 93.66% Approval: 43.33%			
147	Project 2010-10	Project 2010-10 FAC-013-2 Planning Transfer Capability_in	Initial Ballot	10/20/2010	11/3/2010	Quorum: 88.54% Approval: 39.85%			
148	2010 SPM	2010 Standard Processes Manual (Proposed Changes)_in	Initial Ballot	10/28/2010	11/7/2010	Quorum: 81.61% Approval: 93.72%			
149	Project 2007-17	Project 2007-17 Protection System Maintenance: Protection System definition	Recirculation Ballot	11/1/2010	11/11/2010	Quorum: 89.41% Approval: 86.83%			
150	2010 SPM	2010 Standard Processes Manual (Proposed Changes)_rc	Recirculation Ballot	11/9/2010	11/13/2010	Quorum: 87.00% Approval: 92.88%			
151	Project 2009-17	Project 2009-17 - Interpretation Y-W Electric and Tri-State (Revision 2)_rc	Recirculation Ballot	11/19/2010	12/3/2010	Quorum: 87.81% Approval: 82.41%			
152	Project 2008-06	Project 2008-06 Cyber Security 706 (Version 4 CIP Standards)_sb_in	Initial Ballot	12/1/2010	12/10/2010	Quorum: 87.07% Approval: 77.06%			
153	Project 2010-15	Project 2010-15 - Expedited Action Revisions to CIP-005-3	Initial Ballot	12/2/2010	12/11/2010	Quorum: 84.46% Approval: 42.89%			
154	Project 2007-04	Project 2007-04 - Certifying System Operators: PER-003-1	Recirculation Ballot	12/2/2010	12/13/2010	Quorum: 95.50% Approval: 86.91%			
155	Project 2010-13	Project 2010-13 - Relay Loadability Order - PRC-023	Initial Ballot	12/7/2010	12/16/2010	Quorum: 88.00% Approval: 51.51%			
156	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Successive Ballot	12/10/2010	12/20/2010	Quorum: 79.88% Approval: 44.65%			
157	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Non-binding Poll	12/10/2010	12/20/2010	Quorum: 78.00% Approval: 53.00%			
158	Project 2008-06	Project 2008-06 Cyber Security 706 (Version 4 CIP Standards)_sb_rc	Recirculation Ballot	12/20/2010	12/30/2010	Quorum: 90.49% Approval: 80.56%			
159	Project 2010-11	Project 2010-11 TPL Table 1 Footnote B SAR_in	Recirculation Ballot	12/27/2010	1/5/2011	Quorum: 90.42% Approval: 83.33%			
160	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.62% Approval: 22.09%	Oppose 12/16/11		

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161	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.62% Approval: 33.49%	Oppose 12/16/11		
162	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.60% Approval: 26.82%	Oppose 12/16/11		
163	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.60% Approval: 28.04%	Oppose 12/16/11		
164	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 29.60%	Oppose 12/16/11		
165	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 24.15%	Oppose 12/16/11		
166	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 94.02% Approval: 34.30%	Oppose 12/16/11		
167	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 27.28%	Oppose 12/16/11		
168	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 26.61%	Oppose 12/16/11		
169	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 29.88%	Oppose 12/16/11		
170	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation	Initial Ballot	12/16/2011	1/6/2011	Quorum: 92.15% Approval: 42.06%	Oppose 12/16/11		
171	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Initial Ballot	12/16/2011	1/6/2011	Quorum: 92.56% Approval: 25.34%	Oppose 12/16/11		
172	Project 2010-10	Project 2010-10: FAC Order 729_in	Initial Ballot	12/30/2010	1/8/2011	Quorum: 83.23% Approval: 58.16%			
173	Project 2010-10	Project 2010-10: FAC Order 729_rc	Recirculation Ballot	1/14/2011	1/23/2011	Quorum: 86.65% Approval: 68.98%			
174	Project 2010-11	Project 2010-11 TPL Table 1 Footnote B SAR_rc	Recirculation Ballot	1/26/2011	2/5/2011	Quorum: 93.29% Approval: 86.79%	Support 1/5/11		
175	Project 2010-13	Project 2010-13 - Relay Loadability Order - PRC-023	Successive Ballot	1/24/2011	2/14/2011	Quorum: 83.95% Approval: 65.71%	Support 2/11/11		
176	Project 2007-23	Project 2007-23 - Violation Severity Levels	Non-binding Poll	2/9/2011	2/22/2011	Quorum: 78.00% Approval: 72.00%	Support 10/28/10		
177	Project 2007-07	Project 2007-07 Vegetation Management: FAC-003-2	Successive Ballot	2/18/2011	2/28/2011	Quorum: 79.28% Approval: 79.34%	Support 2/22/11		
178	Project 2010-13	Project 2010-13 - Relay Loadability Order - PRC-023	Recirculation Ballot	2/24/2011	3/6/2011	Quorum: 87.35% Approval: 68.83%	Support 2/11/11		
179	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002, IRO-001, and IRO-014	Initial Ballot	2/25/2011	3/7/2011	Quorum: 87.10% Approval: 49.54%	Support 3/2/11		
180	Project 2010-15	Project 2010-15 - Expedited Action Revisions to CIP-005-4	Successive Ballot	4/19/2011	4/28/2011	Quorum: 79.66% Approval: 38.00%	Oppose 4/19/11		
181	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-3	Initial Ballot	4/21/2011	5/2/2011	Quorum: 86.01% Approval: 48.74%	Abstain 4/26/11		
182	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-3	Non-binding Poll	4/21/2011	5/2/2011	Quorum: 75.58% Approval: 73.00%			
183	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Successive Ballot	5/3/2011	5/12/2011	Quorum: 78.33% Approval: 67.00%	No Recommendation		
184	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Non-binding Poll	5/3/2011	5/12/2011	Quorum: 75.00% Approval: 66.00%			
185	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-3	Recirculation Ballot	5/12/2011	5/23/2011	Quorum: 91.25% Approval: 78.92%	Support 5/12/11		
186	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs - TPL-001 through TPL-006	Successive Ballot	5/18/2011	5/31/2011	Quorum: 92.07% Approval: 73.99%			
187	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs - TPL-001 through TPL-006	Non-binding Poll	5/18/2011	5/31/2011	Quorum: 86.79% Approval: 71.9%			
188	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2, TOP-002-2 and TOP-003-2	Initial Ballot	5/31/2011	6/9/2011	Quorum: 88.47% Approval: 48.64%	Oppose 5/31/11		
189	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2, TOP-002-2 and TOP-003-2	Non-binding Poll	5/31/2011	6/9/2011	Quorum: 84.18% Approval: 41.00%			
190	Project 2007-17	Project 2007-17 – Protection System Maintenance and Testing – PRC-005	Recirculation Ballot	6/20/2011	6/30/2011	Quorum: 82.97% Approval: 64.76%	Support 6/28/11		
191	Project 2007-17	Project 2007-17 – Protection System Maintenance and Testing – PRC-005	Non-binding Poll	6/20/2011	6/30/2011	Quorum: 52.63% Approval: 60.00%			
192	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs	Recirculation Ballot	7/13/2011	7/22/2011	Quorum: 94.33% Approval: 75.37%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of “Ballot Periods” column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
193	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-002-3	Recirculation Ballot	7/15/2011	7/25/2011	Quorum: 94.13% Approval: 76.99%	Support 7/22/11		
194	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-005-4	Recirculation Ballot	7/15/2011	7/25/2011	Quorum: 94.13% Approval: 75.17%	Support 7/22/11		
195	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-014-2	Recirculation Ballot	7/15/2011	7/25/2011	Quorum: 94.13% Approval: 76.27%	Support 7/22/11		
196	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-002-3	Non-binding Poll	7/15/2011	7/25/2011	Quorum: 75.37% Approval: 93.00%			
197	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-005-4	Non-binding Poll	7/15/2011	7/25/2011	Quorum: 75.66% Approval: 93.00%			
198	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-014-2	Non-binding Poll	7/15/2011	7/25/2011	Quorum: 75.37% Approval: 89.00%			
199	Project 2007-09	Project 2007-09 – Generator Verification: MOD-026-1	Initial Ballot	7/22/2011	8/1/2011	Quorum: 90.25% Approval: 46.53%	No Consensus 7/28/11		
200	Project 2007-09	Project 2007-09 – Generator Verification: MOD-026-1	Non-binding Poll	7/22/2011	8/1/2011	Quorum: 88.75% Approval: 56.00%			
201	Project 2007-09	Project 2007-09 – Generator Verification: PRC-024-1	Initial Ballot	7/22/2011	8/1/2011	Quorum: 90.82% Approval: 18.23%	No Consensus 7/28/11		
202	Project 2007-09	Project 2007-09 – Generator Verification: PRC-024-1	Non-binding Poll	7/22/2011	8/1/2011	Quorum: 88.35% Approval: 20.79%			
203	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Initial Ballot	9/19/2011	9/29/2011	Quorum: 84.86% Approval: 61.10%	Support 9/21/11		
204	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Non-binding Poll	9/19/2011	9/29/2011	Quorum: 83.13% Approval: 68.68%			
205	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System: Definition of BES	Initial Ballot	9/30/2011	10/10/2011	Quorum: 92.97% Approval: 71.68%	No Consensus 10/3/11		
206	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System: Detailed Information to Support BES Exceptions Request	Initial Ballot	9/30/2011	10/10/2011	Quorum: 89.53% Approval: 64.03%	No Consensus 10/7/111		
207	Project 2007-07	Project 2007-07 Vegetation Management: FAC-003-2	Recirculation Ballot	10/4/2011	10/13/2011	Quorum: 87.17% Approval: 86.25%	Support 2/22/11		
208	Project 2011-INT-01	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	Initial Ballot	11/7/2011	11/16/2011	Quorum: 88.05% Approval: 85.53%	Support 11/8/11		
209	Project 2009-22	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Initial Ballot	11/8/2011	11/17/2011	Quorum: 91.20% Approval: 95.05%	Support 11/8/11		
210	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-001-1	Initial Ballot	11/9/2011	11/18/2011	Quorum: 88.22% Approval: 86.94%	Support 11/10/11		
211	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-3	Initial Ballot	11/9/2011	11/18/2011	Quorum: 85.08% Approval: 85.71%	Support 11/10/11		
212	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-X	Initial Ballot	11/9/2011	11/18/2011	Quorum: 84.82% Approval: 85.31%	Support 11/10/11		
213	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-004-2.1	Initial Ballot	11/9/2011	11/18/2011	Quorum: 84.29% Approval: 96.09%	Support 11/10/11		
214	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-x R1 for Progress Energy	Successive Ballot	11/11/2011	11/21/2011	Quorum: 83.53% Approval: 95.99%	Support 11/14/11		
215	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System and Implementation Plan	Recirculation Ballot	11/10/2011	11/21/2011	Quorum: 95.92% Approval: 81.32%	Support 10/3/11		
216	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System: Detailed Information to Support BES Exceptions Request	Recirculation Ballot	11/10/2011	11/21/2011	Quorum: 93.02% Approval: 81.48%	Support 10/3/11		
217	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Initial Ballot	11/30/2011	12/9/2011	Quorum: 93.92% Approval: 30.82%	Oppose 12/5/11		
218	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Non-binding Poll	11/30/2011	12/9/2011	Quorum: 89.49% Approval: 36.00%			
219	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Initial Ballot	12/2/2011	12/12/2011	Quorum: 87.97% Approval: 36.21%	Oppose 12/5/11		
220	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	12/2/2011	12/12/2011	Quorum: 85.28% Approval: 45.00%			
221	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-x R1 for Progress Energy	Recirculation Ballot	12/9/2011	12/19/2011	Quorum: 88.02% Approval: 96.04%	Support 11/14/11		
222	Project 2011-INT-01	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	Recirculation Ballot	12/12/2011	12/22/2011	Quorum: 90.10% Approval: 92.49%	Support 11/8/11		
223	Project 2009-22	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 92.00% Approval: 94.58%	Support 11/8/11		
224	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-001-1	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 88.48% Approval: 90.10%	Support 11/10/11		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of “Ballot Periods” column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
225	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-3	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 87.17% Approval: 85.38%	Support 11/10/11		
226	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-X	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 86.91% Approval: 85.03%	Support 11/10/11		
227	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-004-2.1a	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 86.65% Approval: 96.43%	Support 11/10/11		
228	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Successive Ballot	1/3/2012	1/12/2012	Quorum: 82.04% Approval: 59.93%	Oppose 1/9/12		
229	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Successive Ballot	1/3/2012	1/12/2012	Quorum: 82.04% Approval: 77.08 %	Support 1/9/12		
230	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Successive Ballot	1/3/2012	1/12/2012	Quorum: 82.04% Approval: 78.95%	Support 1/9/12		
231	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-001-1	Non-binding Poll	1/4/2012	1/13/2012	Quorum: 78.27% Approval: 93.00%			
232	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Non-binding Poll	1/9/2012	1/18/2012	Quorum: 76.41% Approval: 71.42%			
233	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Non-binding Poll	1/9/2012	1/19/2012	Quorum: 81.50% Approval: 67.61%			
234	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Non-binding Poll	1/9/2012	1/19/2012	Quorum: 81.50% Approval: 70.28%			
235	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Successive Ballot	1/30/2012	2/9/2012	Quorum: 81.82% Approval: 54.64%	Oppose 2/7/12		
236	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Successive Ballot	1/30/2012	2/9/2012	Quorum: 82.11% Approval: 80.62%	Support 2/7/12		
237	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Successive Ballot	1/30/2012	2/9/2012	Quorum: 81.82% Approval: 80.21%	Support 2/7/12		
238	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Non-binding Poll	1/30/2012	2/9/2012	Quorum: 80.35% Approval: 71.35%			
239	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Non-binding Poll	1/30/2012	2/9/2012	Quorum: 80.06% Approval: 90.86%			
240	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Non-binding Poll	1/30/2012	2/9/2012	Quorum: 79.77% Approval: 84.69%			
241	Project 2009-26	Project 2009-26 - Interpretation of CIP-004-1 by WECC	Successive Ballot	3/14/2012	3/23/2012	Quorum: 88.55% Approval: 79.61%	Support 3/16/12		
242	Project 2010-INT-05	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy	Initial Ballot	3/14/2012	3/23/2012	Quorum: 89.63% Approval: 94.71%	Support 3/16/12		
243	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR-002 for Constellation	Initial Ballot	3/14/2012	3/23/2012	Quorum: 86.92% Approval: 63.09%	Support 3/16/12		
244	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Successive Ballot	3/19/2012	3/29/2012	Quorum: 81.45% Approval: 61.21%			
245	Project 2007-09	Project 2007-09 Generator Verification: PRC-024-1	Successive Ballot	3/19/2012	3/29/2012	Quorum: 80.38% Approval: 41.09%			
246	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Successive Ballot	3/19/2012	3/29/2012	Quorum: 84.32% Approval: 73.93%	Support 3/19/12		
247	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Non-binding Poll	3/19/2012	3/29/2012	Quorum: 81.93% Approval: 66.12%			
248	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-3	Successive Ballot	3/30/2012	4/9/2012	Quorum: 80.37% Approval: 85.18%	Support 4/5/12		
249	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-X	Successive Ballot	3/30/2012	4/9/2012	Quorum: 80.10% Approval: 85.01%	Support 4/5/12		
250	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.28% Approval: 41.09%	Oppose 4/16/12		
251	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.04% Approval: 36.84%	Oppose 4/16/12		
252	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.04% Approval: 48.70%%	Oppose 4/16/12		
253	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Non-binding Poll	4/6/2012	4/16/2012	Quorum: 86.82% Approval: 43.72%			
254	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Non-binding Poll	4/6/2012	4/16/2012	Quorum: 86.04% Approval: 38.56%			
255	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Non-binding Poll	4/6/2012	4/16/2012	Quorum: 86.53% Approval: 46.38%			
256	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-005-1.1a	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.95% Approval: 92.41%	Support 4/16/12		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of “Ballot Periods” column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
257	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Successive Ballot	4/11/2012	4/20/2012	Quorum: 78.28%% Approval: 75.44%			
258	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Successive Ballot	4/11/2012	4/20/2012	Quorum: 78.02% Approval: 87.22%			
259	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Successive Ballot	4/11/2012	4/20/2012	Quorum: 78.28% Approval: 80.11%			
260	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Non-binding Poll	4/11/2012	4/23/2012	Quorum: 77.21% Approval: 69.84%			
261	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Non-binding Poll	4/11/2012	4/23/2012	Quorum: 77.48% Approval: 67.64%			
262	Project 2009-26	Project 2009-26 - Interpretation of CIP-004-1 by WECC	Recirculation Ballot	4/20/2012	4/30/2012	Quorum: 90.96% Approval: 80.08%	Support 3/16/12		
263	Project 2010-INT-05	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy	Recirculation Ballot	4/20/2012	4/30/2012	Quorum: 92.68% Approval: 94.61%	Support 3/16/12		
264	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-3	Recirculation Ballot	4/24/2012	5/3/2012	Quorum: 81.72% Approval: 87.34%			
265	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-X	Recirculation Ballot	4/24/2012	5/3/2012	Quorum: 81.94% Approval: 87.32%			
266	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-005-1.1b	Recirculation Ballot	4/24/2012	5/3/2012	Quorum: 90.44% Approval: 93.23%			
267	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Recirculation Ballot	4/27/2012	5/6/2012	Quorum: 79.36% Approval: 76.84%	Abstain 4/19/12		
268	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Recirculation Ballot	4/27/2012	5/6/2012	Quorum: 79.36% Approval: 88.11%	Support 4/19/12		
269	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Recirculation Ballot	4/27/2012	5/6/2012	Quorum: 79.36% Approval: 80.79%	Support 4/19/12		
270	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.63% Approval: 37.37%	Abstain 5/17/12		
271	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.45% Approval: 60.55%	Abstain 5/17/12		
272	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.40% Approval: 38.81%	Abstain 5/17/12		
273	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.98% Approval: 55.08%	Abstain 5/17/12		
274	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.22% Approval: 38.50%	Abstain 5/17/12		
275	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.01% Approval: 45.78%	Abstain 5/17/12		
276	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.19% Approval: 67.19%	Abstain 5/17/12		
277	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.01% Approval: 60.19%	Abstain 5/17/12		
278	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.39% Approval: 47.92%	Abstain 5/17/12		
279	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.39% Approval: 58.23%	Abstain 5/17/12		
280	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation	Successive Ballot	5/11/2012	5/21/2012	Quorum: 85.12% Approval: 66.23%	Abstain 5/17/12		
281	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Successive Ballot	5/11/2012	5/21/2012	Quorum: 84.09% Approval: 47.88%	Abstain 5/17/12		
282	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Successive Ballot	5/15/2012	5/24/2012	Quorum: 84.43% Approval: 46.18%			
283	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	5/15/2012	5/24/2012	Quorum: 79.95% Approval: 52.67%			
284	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Initial Ballot	6/11/2012	6/20/2012	Quorum: 84.14% Approval: 21.11%	Oppose 6/13/12		
285	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	6/11/2012	6/20/2012	Quorum: 81.01% Approval: 28.30%			
286	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Successive Ballot	6/18/2012	6/27/2012	Quorum: 79.46% Approval: 79.00%			
287	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Non-binding Poll	6/18/2012	6/27/2012	Quorum: 75.00% Approval: 70.21%			
288	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR -002 for Constellation	Successive Ballot	6/18/2012	6/27/2012	Quorum: 85.98% Approval: 68.22%	Support 6/26/12		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of “Ballot Periods” column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
289	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Initial Ballot	6/26/2012	7/5/2012	Quorum: 84.24% Approval: 23.82%	Oppose 6/27/12		
290	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Non-binding Poll	6/26/2012	7/5/2012	Quorum: 82.26% Approval: 25.19%			
291	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Recirculation Ballot	6/27/2012	7/6/2012	Quorum: 85.34% Approval: 81.71%			
292	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Recirculation Ballot	6/27/2012	7/6/2012	Quorum: 85.04% Approval: 81.72%			
293	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Non-binding Poll	6/27/2012	7/6/2012	Quorum: 84.16% Approval: 79.16%			
294	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Non-binding Poll	6/27/2012	7/6/2012	Quorum: 83.87% Approval: 86.91%			
295	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Successive Ballot	6/27/2012	7/9/2012	Quorum: 75.37% Approval: 72.16%	No Consensus 7/5/12		
296	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Non-binding Poll	6/27/2012	7/11/2012	Quorum: 75.37% Approval: 73.71%			
297	Project 2011-INT-02	Project 2011-INT-02 - Rapid Revision of VAR-002 for Constellation	Recirculation Ballot	7/18/2012	7/27/2012	Quorum: 90.97% Approval: 69.81%	Support 6/26/12		
298	Project 2011-INT-02	Project 2011-INT-02 - Rapid Revision of VAR-002 for Constellation	Non-binding Poll	7/18/2012	7/27/2012	Quorum: 81.31% Approval: 60.93%			
299	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Initial Ballot	7/20/2012	7/30/2012	Quorum: 80.39% Approval: 79.28%	Oppose 7/20/12		
300	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Non-binding Poll	7/20/2012	7/30/2012	Quorum: 78.26% Approval: 76.07%			
301	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Initial Ballot	7/24/2012	8/2/2012	Quorum: 83.11% Approval: 54.16%	Oppose 7/20/12		
302	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Successive Ballot	8/17/2012	8/27/2012	Quorum: 78.11% Approval: 80.31%	Support 6/22/12		
303	Project 2009-19	Project 2009-19 – Interpretation of BAL-002 by NWPP Reserve Sharing Group	Successive Ballot	8/23/2012	9/4/2012	Quorum: 79.21% Approval: 87.78%	Support 2/22/10		
304	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Initial Ballot	8/29/2012	9/7/2012	Quorum: 86.71% Approval: 37.68%	Support 9/5/12		
305	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Non-binding Poll	8/29/2012	9/7/2012	Quorum: 84.17% Approval: 37.36%			
306	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Recirculation Ballot	9/6/2012	9/17/2012	Quorum: 80.35% Approval: 75.01%			
307	Project 2007-02	Project 2007-02 - Operating Personnel Communication Protocols	Successive Ballot	9/11/2012	9/20/2012	Quorum: 77.70% Approval: 50.57%	Support 9/15/12		
308	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	9/11/2012	9/20/2012	Quorum: 84.05% Approval: 54.07%			
309	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Recirculation Ballot	9/12/2012	9/21/2012	Quorum: 85.36% Approval: 87.34%			
310	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Successive Ballot	9/18/2012	9/27/2012	Quorum: 78.54% Approval: 63.40%	No Consensus 9/27/12		
311	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	9/18/2012	9/27/2012	Quorum: 78.93% Approval: 71.04%			
312	Project 2009-19	Project 2009-19 - Interpretation of BAL-002-0 NWPP Reserve Sharing Group	Recirculation Ballot	9/28/2012	10/8/2012	Quorum: 85.11% Approval: 90.34%	Support 2/22/10		
313	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 74.85%	Support 10/4/12		
314	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.37% Approval: 89.50%	Support 10/4/12		
315	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 85.58%	Support 10/4/12		
316	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 89.46%	Support 10/4/12		
317	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 92.11%	Support 10/4/12		
318	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 87.73%	Support 10/4/12		
319	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 91.74%	Support 10/4/12		
320	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 91.73%	Support 10/4/12		

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321	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 84.60%	Support 10/4/12		
322	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 92.90%	Support 10/4/12		
323	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation	Successive Ballot	10/1/2012	10/10/2012	Quorum: 78.93% Approval: 94.00%	Support 10/4/12		
324	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Successive Ballot	10/1/2012	10/10/2012	Quorum: 79.13% Approval: 91.59%	Support 10/4/12		
325	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Initial Ballot	10/3/2012	10/12/2012	Quorum: 87.50% Approval: 63.25%	Support 10/4/12		
326	VRFs and VSLs	Revisions to Outstanding VRFs and VSLs	Non-binding Poll	10/10/2012	10/23/2012	Quorum: 78.57% Approval: 73.02%			
327	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Recirculation Ballot	10/15/2012	10/24/2012	Quorum: 81.08% Approval: 80.51%	Support 6/22/12		
328	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 75.55% Approval: 76.50%			
329	Project 2007-09	Project 2007-09 Generator Verification: PRC-024-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 75.00% Approval: 57.24%			
330	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Successive Ballot	10/19/2012	10/31/2012	Quorum: 83.61% Approval: 68.31%			
331	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 82.34% Approval: 71.53%			
332	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 82.07% Approval: 70.64%			
333	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 75.88% Approval: 77.10%			
334	Project 2007-09	Project 2007-09 Generator Verification: PRC-024-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 75.40% Approval: 52.72%			
335	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 77.94% Approval: 64.24%			
336	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 78.06% Approval: 68.93%			
337	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 78.51% Approval: 63.63%			
338	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 78.59%	Support 10/4/12		
339	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 92.75%	Support 10/4/12		
340	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 89.73%	Support 10/4/12		
341	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 93.73%	Support 10/4/12		
342	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.53%	Support 10/4/12		
343	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 91.79%	Support 10/4/12		
344	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.47%	Support 10/4/12		
345	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 94.60%	Support 10/4/12		
346	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 88.99%	Support 10/4/12		
347	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.67%	Support 10/4/12		
348	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation Plan	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 83.47% Approval: 94.91%	Support 10/4/12		
349	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 83.47% Approval: 93.23%	Support 10/4/12		
350	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Recirculation Ballot	10/24/2012	11/5/2012	Quorum: 85.14% Approval: 71.39%			
351	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	10/24/2012	11/5/2012	Quorum: 78.93% Approval: 71.04%			
352	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Successive Ballot	10/26/2012	11/6/2012	Quorum: 82.04% Approval: 76.08%	Support 11/5/12		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of “Ballot Periods” column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
353	Project 2010-11	Project 2010-11 TPL footnote b Initial Ballot October 2012_in	Initial Ballot	11/9/2012	11/19/2012	Quorum: 80.45% Approval: 56.18%			
354	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Initial Ballot	11/26/2012	12/5/2012	Quorum: 84.81% Approval: 72.57%	Oppose 12/5/12		
355	Project 2013-02	Project 2013-02 - Paragraph 81	Initial Ballot	11/30/2012	12/10/2012	Quorum: 75.77% Approval: 96.45%	Support 12/10/12		
356	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Successive Ballot	12/4/2012	12/13/2012	Quorum: 76.78% Approval: 53.57%	No Consensus 12/13/12		
357	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	12/4/2012	12/13/2012	Quorum: 77.22% Approval: 57.91%			
358	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Successive Ballot	12/7/2012	12/17/2012	Quorum: 76.47% Approval: 33.23%	Oppose 12/17/12		
359	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Non-binding Poll	12/7/2012	12/17/2012	Quorum: 75.58% Approval: 34.80%			
360	Project 2012-INT-05	Interpretation 2012-INT-05: CIP-002-3 for OGE	Initial Ballot	12/11/2012	12/20/2012	Quorum: 84.50% Approval: 95.60%	Support 12/19/12		
361	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Successive Ballot	12/11/2012	12/20/2012	Quorum: 83.24% Approval: 84.48%	Support 12/19/12		
362	Project 2007-09	Project 2007-09_Generator Verification: MOD-025-2	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.89% Approval: 73.06%			
363	Project 2007-09	Project 2007-09_Generator Verification: MOD-026-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 79.00% Approval: 79.36%			
364	Project 2007-09	Project 2007-09_Generator Verification: MOD-027-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.68% Approval: 74.27%			
365	Project 2007-09	Project 2007-09_Generator Verification: PRC-019-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 85.87% Approval: 73.63%			
366	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.19% Approval: 76.53%			
367	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Successive Ballot	1/2/2013	1/11/2013	Quorum: 78.16% Approval: 60.31%	Support 1/11/13		
368	Project 2007-09	Project 2007-09 - Generator Verification - PRC-024-1	Non-binding Poll	1/2/2013	1/11/2013	Quorum: 76.38% Approval: 55.68%			
369	Project 2010-11	Project 2010-11 Successive Ballot December 2012_in	Successive Ballot	1/2/2013	1/11/2013	Quorum: 85.47% Approval: 65.77%	No Consensus 1/11/13		
370	Project 2010-14.1	Project 2010-14.1_- Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-012-1	Initial Ballot	1/4/2013	1/14/2013	Quorum: 83.94% Approval: 21.80%	Oppose 1/11/13		
371	Project 2010-14.1	Project 2010-14.1_- Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-012-1	Non-binding Poll	1/4/2013	1/14/2013	Quorum: 82.23% Approval: 24.27%			
372	Project 2013-02	Project 2013-02 - Paragraph 81	Recirculation Ballot	1/8/2013	1/17/2013	Quorum: 84.60% Approval: 95.22%	Support 12/10/12		
373	Project 2012-INT-05	Interpretation 2012-INT-05: CIP-002-3 for OGE	Recirculation Ballot	1/14/2013	1/23/2013	Quorum: 87.13% Approval: 99.09%	Support 12/19/12		
374	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Recirculation Ballot	1/18/2013	1/28/2013	Quorum: 85.90% Approval: 85.57%	Support 12/19/12		
375	Project 2010-11	Project 2010-11 Recirculation Ballot Jan 2013_in	Recirculation Ballot	1/22/2013	1/31/2013	Quorum: 88.55% Approval: 69.63%	No Consensus 1/11/13		
376	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Recirculation Ballot	1/22/2013	1/31/2013	Quorum: 85.67% Approval: 77.61%	Oppose 12/5/12		
377	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Successive Ballot	2/11/2013	2/20/2013	Quorum: 77.62% Approval: 50.66%	Support 9/5/12		
378	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Non-binding Poll	2/11/2013	2/20/2013	Quorum: 75.38% Approval: 50.60%			
379	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Successive Ballot	2/15/2013	2/28/2013	Quorum: 78.80% Approval: 89.01%	Support 1/11/13		
380	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Non-binding Poll	2/15/2013	2/28/2013	Quorum: 76.38% Approval: 84.24%			
381	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Initial Ballot	3/1/2013	3/11/2013	Quorum: 76.36% Approval: 54.65%			
382	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Successive Ballot	3/13/2013	3/22/2013	Quorum: 77.48% Approval: 84.27%	No Consensus 3/22/13		NPCC to abstain - international nature of the ERO and BPS is not used in Reliability Standards

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383	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	Initial Ballot	3/13/2013	3/22/2013	Quorum: 88.58% Approval: 97.18%	Support 3/14/13		
384	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	Initial Ballot	3/13/2013	3/22/2013	Quorum: 88.52% Approval: 98.89%	Support 3/14/13		
385	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Recirculation Ballot	3/18/2013	3/27/2013	Quorum: 81.33% Approval: 89.44%	Support 1/11/13		
386	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Successive Ballot	3/27/2013	4/5/2013	Quorum: 78.39% Approval: 57.50%	No Consensus 4/4/13		The RSC did not reach a full consensus however the majority of respondents had indicated they will support the standard - see comment form for further details. Some believe the standard is not necessary and that existing whitepapers alleviate the need for it. In recognition of the NERC BOT's expectations that COM-003 will be approved by the industry and brought before them for approval, NPCC has voted affirmatively and will supply comments for the record outlining our concerns.
387	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	3/27/2013	4/5/2013	Quorum: 77.97% Approval: 54.28%			
388	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.60% Approval: 66.98%	No Consensus 4/23/13		The majority of NPCC’s Balancing Authorities have indicated support for the standard, however NPCC as the Regional Entity has concerns based on results of the field trials that were conducted. These field trials have indicated the potential for an increased number of SOL violations as well as potential for increased ACE due to large inadvertent flows with the proposed BAAL limits based on frequency triggers. To be respectful of the positions of the NPCC BAs who will have to implement this new methodology and the support expressed, NPCC as the Regional Entity will cast an Abstention
389	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-002-2	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.51% Approval: 42.75%	Oppose 4/23/13		There is a lack of technical justification for the 500 MW threshold within the standard-NPCC will submit suggested improvements

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390	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-013-1	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.51% Approval: 23.84%	Oppose 4/23/13		Losses of large blocks of load are typically caused by coincident transmission contingencies. Excessive and uninformed adjustments made to generation in order to bring the ACE to zero may well lead to further transmission issues. NPCC will submit suggested improvements
391	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
392	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-002-2	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
393	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-013-1	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
394	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Recirculation Ballot	4/18/2013	4/29/2013	Quorum: 80.70% Approval: 88.15%	No Consensus 3/22/13		
395	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Successive ballot	5/15/2013	5/24/2013	Quorum: 81.25% Approval: 69.23%	Support 5/23/13		The Regional Standard Committee has not expressed any concerns of significance that would warrant a ballot to reject, therefore the RSC recommends a yes vote, “Affirmative”, to accept the standard
396	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Non-binding Poll	5/15/2013	5/24/2013	Quorum: 80.17% Approval: 61.11%			
397	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	Successive Ballot	6/24/2013	7/3/2013	Quorum: 77.65% Approval: 52.71%			
398	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	Non-binding Poll	6/24/2013	7/3/2013	Quorum: 77.12% Approval: 52.48%			
399	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Initial Ballot	7/3/2013	7/12/2013	Quorum: 85.53% Approval: 49.73%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of “Ballot Periods” column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
400	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	Successive Ballot	7/10/2013	7/19/2013	Quorum: 76.32% Approval: 58.36%	No Consensus 7/19/13 [Due to the concerns expressed over the potential actions by the NERC BOT and FERC as well as the incremental improvement of the standard over the previous versions, NPCC as the Regional Entity will support the standard and submit comments.]		organizations support the standard as written however some members expressed concern that in order to measure compliance with R1 and R2, the standard will require all Reliability Directives to be investigated to determine if RC approved and documented communication protocols have been violated. Also it was identified that TO, BA communication protocols would have to approved by the RC potentially causing some legal issues if protocols aren’t approved and casts question on the enforcement of those protocols. NPCC will be submitting some helpful comments should the standard pass and some non-substantive revision be performed prior to the “final” (previously named recirculation) ballot.
401	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	Non-binding Poll	7/10/2013	7/19/2013	Quorum: 76.20% Approval: 55.37%			
402	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	Successive Ballot	7/10/2013	7/19/2013	Quorum: 85.05% Approval: 72.43%	Support 7/19/13		
403	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	Non-binding Poll	7/10/2013	7/19/2013	Quorum: 82.51% Approval: 64.59%			
404	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Final Ballot	7/16/2013	7/25/2013	Quorum: 92.31% Approval: 74.54%	No Consensus 7/22/13		The RSC has not reached a full consensus however the majority are in support. Issues outstanding for those not in support are concern over “hitting limits” more frequently and potential issues with BA’s potentially “dragging” on the interconnection. NPCC will be voting affirmative on the standard.
405	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023-3	Initial Ballot	7/26/2013	8/5/2013	Quorum: 80.05% Approval: 93.00%	Support 8/5/13		
408	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025-1	Final Ballot	8/2/2013	8/12/2013	Quorum: 89.13% Approval: 76.52%	Support 8/12/13		
406	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Initial Ballot	8/2/2013	8/12/2013	Quorum: 76.32% Approval: 62.74%	Support 8/9/13		
407	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Non-binding Poll	8/2/2013	8/12/2013	Quorum: 75.89% Approval: 55.45%			
409	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Initial Ballot	8/14/2013	8/23/2013	Quorum: 78.33% Approval: 79.42%	Support 8/23/13		
410	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Non-binding Poll	8/14/2013	8/23/2013	Quorum: 77.45% Approval: 81.37%			
411	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Ballot	8/16/2013	8/26/2013	Quorum: 76.14% Approval: 51.10%	No Consensus 8/26/13		NPCC to support with comments
412	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Non-binding Poll	8/16/2013	8/26/2013	Quorum: 75.98% Approval: 53.29%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of “Ballot Periods” column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
413	Project 2010-01	Project 2010-01 - Training - PER-005-2	Ballot	8/23/2013	9/3/2013	Quorum: 75.25% Approval: 34.46%	No Consensus 8/31/13		NPCC to support with comments The most contentious issues raised by RSC members was surrounding the Control Center definition and the potential to vastly expand those needing training subject to the standard and compliance and that there was no need for a standard, rather, the FERC Directives should be addressed through other means.
414	Project 2010-01	Project 2010-01 - Training - PER-005-2	Non-binding Poll	8/23/2013	9/3/2013	Quorum: 80.45% Approval: 34.24%			
415	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	Ballot	8/23/2013	9/3/2013	Quorum: 81.89% Approval: 43.79%	Oppose 8/31/13		The standard, in the view of the group, has extensive issues including but not limited to, applicability issues, lacks clarity, missing measures, quality, and other substantive issues. NPCC will be submitting detailed comments to address these issues. The RSC does not believe it would be beneficial to support the standard at this point as the next step, if it fails the initial ballot, would still require an additional ballot prior to moving to recirculation due to the substantive changes that are needed for the next revision. NPCC will be submitting helpful comments to NERC and supporting the drafting team effort.
416	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	Non-binding Poll	8/23/2013	9/3/2013	Quorum: 79.95% Approval: 44.23%			
417	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	Ballot	8/26/2013	9/4/2013	Quorum: 82.29% Approval: 41.24%	Support 8/31/13		
418	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	Non-binding Poll	8/26/2013	9/4/2013	Quorum: 79.66% Approval: 40.00%			
419	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Ballot	8/26/2013	9/4/2013	Quorum: 81.96% Approval: 55.76%	Support 8/31/13		
420	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Non-binding Poll	8/26/2013	9/4/2013	Quorum: 80.35% Approval: 58.97%			
421	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Additional Ballot	8/26/2013	9/4/2013	Quorum: 78.68% Approval: 66.11%	Support 8/31/13		
426	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023-3	Final Ballot	9/4/2013	9/13/2013	Quorum: 85.93% Approval: 90.83%	Support 8/5/13		
422	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2, BAL-013-1	Ballot	9/6/2013	9/16/2013	Quorum: 76.15% Approval: 58.23%	No Consensus 9/12/13		

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423	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2, BAL-013-1	Non-binding Poll	9/6/2013	9/16/2013	Quorum: 75.69% Approval: 59.66%			
424	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	Final Ballot	9/11/2013	9/20/2013	Quorum: 91.64% Approval: 98.61%	Support 3/14/13		
425	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	Final Ballot	9/11/2013	9/20/2013	Quorum: 90.98% Approval: 98.92%	Support 3/14/13		
427	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Additional Ballot	10/9/2013	10/21/2013	Quorum: 77.58% Approval: 88.75%	Support 10/16/13		
428	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Non-binding Poll	10/9/2013	10/21/2013	Quorum: 75.89% Approval: 90.04%			
429	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Final Ballot	10/16/2013	10/25/2013	Quorum: 85.71% Approval: 85.38%			
430	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Additional Ballot	10/18/2013	10/29/2013	Quorum: 75.83% Approval: 72.55%	Support 10/21/13		
431	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Final Ballot	10/25/2013	11/4/2013	Quorum: 86.90% Approval: 91.95%			
432	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Additional Ballot	10/25/2013	11/7/2013	Quorum: 76.67% Approval: 58.24%	No Consensus 11/1/13		
433	Project 2010-01	Project 2010-01 - Training - PER-005-2	Additional Ballot	11/1/2013	11/12/2013	Quorum: 76.23% Approval: 56.48%	Support 11/11/13		
434	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Initial Ballot	11/4/2013	11/13/2013	Quorum: 76.12% Approval: 67.35%	Support 11/5/13		
435	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-006-4	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 75.58%	Support 11/5/13		
436	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-009-2	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 68.40%	Support 11/5/13		
437	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 58.03%	Support 11/5/13		
438	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-011-1	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.52% Approval: 71.35%	Support 11/5/13		
439	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Initial Ballot	11/4/2013	11/15/2013	Quorum: 76.42% Approval: 77.82%	Support 11/5/13		
440	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Final Ballot	11/8/2013	11/18/2013	Quorum: 81.68% Approval: 74.34%	Support 10/21/13		
441	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Additional Ballot	11/8/2013	11/20/2013	Quorum: 81.69% Approval: 82.97%	No Consensus 8/26/13		
442	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1	Additional Ballot	11/8/2013	11/20/2013	Quorum: 79.05% Approval: 73.46%	Support 8/31/13		
443	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Additional Ballot	11/8/2013	11/20/2013	Quorum: 79.84% Approval: 69.42%	Support 8/31/13		
444	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Additional Ballot	11/13/2013	11/22/2013	Quorum: 80.54% Approval: 57.59%	Support 8/31/13		
445	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4	Additional Ballot	11/15/2013	11/25/2013	Quorum: 80.81% Approval: 69.43%			
446	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-002-3	Additional Ballot	11/15/2013	11/25/2013	Quorum: 81.06% Approval: 66.09%			
447	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2	Additional Ballot	12/2/2013	12/12/2013	Quorum: 75.29% Approval: 64.24%	No Consensus 12/9/13	Affirmative	

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of “Ballot Periods” column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
448	Project 2007-11	Project 2007-11 Disturbance Monitoring - PRC-002-2	Initial Ballot	12/6/2013	12/16/2013	Quorum: 82.25% Approval: 43.29%	No Consensus 12/15/13	Affirmative	Highlights of comments received expressed: • Agreement with the methodology to determine BES locations for which data had to be captured • Use of the term “locations” • DDR for Flowgates, IROLs • Clarification needed for some data that is to be captured • Editorial suggestions
449	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1	Final Ballot	12/6/2013	12/16/2013	Quorum: 87.53% Approval: 77.49%	Support 8/31/13	Affirmative	
450	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-006-4	Final Ballot	12/10/2013	12/20/2013	Quorum: 85.07% Approval: 80.77%	Support 11/5/13	Affirmative	
451	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-009-2	Final Ballot	12/10/2013	12/20/2013	Quorum: 85.07% Approval: 72.86%	Support 11/5/13	Affirmative	
452	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-011-1	Final Ballot	12/10/2013	12/20/2013	Quorum: 84.78% Approval: 72.91%	Support 11/5/13	Affirmative	
453	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Final Ballot	12/11/2013	12/20/2013	Quorum: 87.16% Approval: 86.40%	No Consensus 8/26/13	Affirmative	
454	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4	Final Ballot	12/13/2013	12/23/2013	Quorum: 84.34% Approval: 75.35%		Affirmative	
455	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-027-1	Additional Ballot	12/9/2013	12/31/2013	Quorum: 76.60% Approval: 65.71%	No Consensus 12/27/13	Affirmative	
456	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Additional Ballot	1/10/2014	1/21/2014	Quorum: 76.92% Approval: 81.41%	Support 8/31/13	Affirmative	
457	Project 2010-01	Project 2010-01 - Training - PER-005-2	Additional Ballot	1/8/2014	1/22/2014	Quorum: 7912% Approval: 74.63%	Support 11/11/13	Affirmative	
458	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Additional Ballot	1/10/2014	1/22/2014	Quorum: 75.22% Approval: 81.19%	Support 11/5/13	Affirmative	
459	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Additional Ballot	1/10/2014	1/22/2014	Quorum: 75.22% Approval: 90.23%	Support 11/5/13	Affirmative	
460	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Additional Ballot	1/16/2014	1/29/2014	Quorum: 76.12% Approval: 92.17%	Support 11/5/13	Affirmative	
461	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Additional Ballot	1/22/2014	1/31/2014	Quorum: 76.03% Approval: 71.86%	No Consensus 11/1/13	Affirmative	Ballot Period Extended to 2/4/14
462	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Final Ballot	1/27/2014	2/5/2014	Quorum: 83.88% Approval: 83.44%	Support 11/5/13	Affirmative	
463	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Final Ballot	1/27/2014	2/5/2014	Quorum: 83.58% Approval: 91.51%	Support 11/5/13	Affirmative	
464	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Final Ballot	1/27/2014	2/5/2014	Quorum: 82.49% Approval: 82.45%	Support 8/31/13	Affirmative	
465	Project 2010-01	Project 2010-01 - Training - PER-005-2	Final Ballot	1/27/2014	2/5/2014	Quorum: 84.02% Approval: 77.06%	Support 11/11/13	Affirmative	
466	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Final Ballot	1/31/2014	2/10/2014	Quorum: 81.79% Approval: 90.12%	Support 11/5/13	Affirmative	
467	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Additional Ballot	2/21/2014	3/3/2014	Quorum: 75.06% Approval: 62.63%	Support 9/5/12	Affirmative	Ballot Period Extended to 3/11/14
468	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Final Ballot	3/28/2014	4/7/2014	Quorum: 78.21% Approval: 77.62%	Support 3/28/14	Affirmative	
469	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Additional Ballot	4/1/2014	4/10/2014	Quorum: 76.92% Approval: 83.40%	Support 8/31/13	Affirmative	
470	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-002-3	Additional Ballot	4/4/2014	4/14/2014	Quorum: 78.03% Approval: 82.40%		--	
471	Project 2014-04	Project 2014-04 Physical Security - CIP-014-1	Initial Ballot	4/20/2014	4/24/2014	Quorum: 88.60% Approval: 82.07%	Support 4/23/14	Abstain	
472	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Final Ballot	4/25/2014	5/5/2014	Quorum: 80.37% Approval: 90.00%	Support--4/25/14	Affirmative	

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473	Project 2013-04	Project 2013-04 - Voltage and Reactive Control - VAR-001-4, VAR-002-3	Final Ballot	4/23/2014	5/5/2014	Quorum: 83.84% Approval: 88.26%	Support--4/10/14	Affirmative		
474	Project 2014-04	Project 2014-04 - Physical Security - CIP-014-1	Final Ballot	5/1/2014	5/5/2014	Quorum: 92.53% Approval: 85.61%	Support--4/23/14	Abstain		
475	Project 2010-02	Project 2010-02 - Connecting Facilities to the Grid - FAC-001-2 and FAC-002-2	Initial Ballot	5/6/2014	5/15/2014	Quorum: 85.79%/79.08% Approval: 86.28%/78.81%	No Consensus--5/15/14	Reject		
476	Project 2012-13	Project 2012-13 - NUC - Nuclear Plant Interface Coordination	Initial Ballot	5/13/2014	5/22/2014	Quorum: 80.60% Approval: 97.36%	Support--5/20/14	Affirmative		
477	Project 2007-17.3	Project 2007-17.3 - Protection System Maintenance and Testing - Phase 3 (Sudden Pressure Relays) - PRC-005-X	Initial Ballot	5/23/2014	6/2/2014	Quorum: 85.42% Approval: 47.89%	Support	Affirmative		
478	Project 2010-13.3	Project 2010-13.3 - Phase 3 of Relay Loadability: Stable Power Swings	Initial Ballot	5/30/2014	6/9/2014	Quorum: 79.06% Approval: 17.02%	Does not Support--6/6/14	Negative		
475	Project 2010-02	Project 2010-02 - Connecting Facilities to the Grid - FAC-001-2 and FAC-002-2	Final Ballot	6/12/2014	6/23/2014	Quorum: Approval: 89.03%/83.46%	Support	Affirmative		
479	Project 2007-11	Project 2007-11 - Disturbance Monitoring - PRC-002-2	Additional Ballot	6/13/2014	6/23/2014	Quorum: 77.69% Approval: 52.29%	Support	Affirmative	Extended to achieve a quorum.	Last RSC M
480	Project 2010-05.1	Project 2010-05.1 - Protection System: Phase 1 (Misoperations) - PRC-004	Additional Ballot	6/20/2014	7/9/2014	Quorum: 76.98% Approval: 74.53%	Support	Affirmative	Extended to achieve a quorum.	
481	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	Ballot	6/23/2014	7/2/2014	Quorum: 82.32%/82.59%/82.59%/82.85%/82.85%/82.06%/82.59%/82.85%/82.85%/81.00%/80.74% Approval: 68.57%/36.94%/47.87%/60.26%/61.67%/57.94%/30.99%/62.18%/63.07%/62.64%/64.70%	No Consensus--6/24/14	Affirmative Negative Affirmative Affirmative Affirmative Affirmative Negative Affirmative Affirmative		
482	Project 2012-13	Project 2012-13 NUC - Nuclear Plant Interface Coordination	Final Ballot	6/24/2014	7/3/2014	Quorum: 88.63% Approval: 97.23%	Support--6/23/14	Affirmative		
483	Project 2014-02	Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions Rich HTML Content 1 http://www.nerc.com/pa/Stand/Pages/Project-2014-XX-Critical-Infrastructure-Protection-Version-5-Revisions.aspx	Final Ballot	7/7/2014	7/16/2014	Quorum: 80.73%/80.49%/80.00%/80.24%/80.24%/80.49%/80.24%/78.29% Approval: 35.67%/80.76%/76.24%/78.41%/85.32%/49.42%/82.55%/78.58%	CIP-003 No CIP-004 Yes CIP-006 Yes CIP-007 Yes CIP-009 Yes CIP-010 Yes CIP-011 Yes Definitions Yes Support--7/14/14			
484	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)	Final Ballot	7/16/2014	7/25/2014	Quorum: 78.92% Approval: 58.88%	Support--7/23/14			
485	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	7/18/2014	7/28/2014	Quorum: 79.49%/80.15%/80.00%/80.83%/80.36% Approval: 91.38%/92.20%/89.51%/90.58%/87.09%	Support--7/24/14	Affirmative		
486	Project 2012-13	Project 2013-03 Geomagnetic Disturbance Mitigation	Final Ballot	7/21/2014	7/30/2014	Quorum: 82.67% Approval: 55.77%		Affirmative		
487	Project 2012-13	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Initial Ballot	7/29/2014	8/7/2014	Quorum: 76.37% Approval: 76.91%		Affirmative		
488	Project 2012-13	Project 2009-03 Emergency Operations	Initial Ballot	8/6/2014	8/15/2014	Quorum: 77.66% Approval: 42.27%	Negative--8/14/14	Negative		
489	Project 2014-01	Project 2010-05.1 - Protection System: Phase 1 (Misoperations) - PRC-004	Final Ballot	7/29/2014	8/7/2014	Quorum: 77.94% Approval: 79.75%	Support	Affirmative		
490	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	8/27/2014	9/5/2014	Quorum: 85.32%/86.01% Approval: 95.35%/95.86%	Support	Affirmative		
491	Project 2007-17.3	Project 2007-17.3 - Protection System Maintenance and	Additional Ballot	9/3/2014	9/12/2014	Quorum: 84.33%	Support--9/4/14	Affirmative		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of “Ballot Periods” column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
						Approval: 76.03%	~~Support 9/4/14~~	~~Affirmative~~	
492	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	Additional Ballot	9/10/2014	9/19/2014	Quorum: 85.75%/84.96%/84.96%/85.22%/84.96%/85.22%/85.49%/85.22%/86.28%/83.11%/83.91%	TOP-001-3: Negative TOP-002-4: Affirmative TOP-003-3: Affirmative IRO-001-4: No consensus however the majority indicated an Affirmative vote IRO-002-4: Negative IRO-008-2: No consensus, a majority indicated a Negative and the others indicated abstention IRO-010-2: Affirmative IRO-014-3: Negative IRO-017-1: Affirmative Implementation Plan and Definitions: Affirmative		
						Approval: 76.12%/74.23%/75.67%/85.49%/75.96%/78.67%/48.73%/78.87%/87.03%/93.34%/90.13%			
493	Project 2010-14.1	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Additional Ballot	9/23/2014	10/2/2014	Quorum: 79.94% Approval: 46.73%	Negative--10/1/14		
494	Project 2010-13.3	Project 2010-13.3 - Phase 3 of Relay Loadability: Stable Power Swings	Additional Ballot	9/26/2014	10/6/2014	Quorum: 79.01% Approval: 53.02%	Affirmative--10/1/14		
495	Project 2012-13	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Additional Ballot	9/29/2014	10/8/2014	Quorum: 83.24%/84.82% Approval: 80.69%/84.05%	Affirmative--10/7/14	Affirmative	
496	Project 2012-13	Project 2013-03 Geomagnetic Disturbance Mitigation	Additional Ballot	10/1/2014	10/10/2014	Quorum: 82.93% Approval: 57.95%	Affirmative--10/7/14		
497	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)	Additional Ballot	10/3/2014	10/14/2014	Quorum: 80.54% Approval: 75.79% Approval:	Affirmative--10/7/14		

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
1.	N/A	Standards Project Prioritization Reference Document and Tool	Project Prioritization Tool		1/21/11	2/10/11	Yes 2/10/11
2.	Project 2007-23	Project 2007-23 - Violation Severity Levels	VSLs		1/20/11	2/18/11	Yes 2/18/11
3.	N/A	CAN-0015--Draft CAN-0015 Unavailability of NERC Tools	CAN-0015 Unavailability of NERC Tools		2/4/11	2/18/11	Yes 2/18/11
4	N/A	CAN-0016--Draft CAN-0016 CIP-001-1 R1 - Applicability to Non-BES	CAN-0016 CIP-001-1, R1		2/4/11	2/18/11	Yes 2/18/11
5.	N/A	CAN-0018--Draft CAN-0018 FAC-008 R.1.2.1 - Terminal Equipment	CAN-0018 FAC-008, R.1.2.1		2/4/11	2/18/11	Yes 2/18/11
6.	Regional Standard	Regional Reliability Standards - PRC-006-NPCC-1 - Automatic Underfrequency Load Shedding	PRC-006-NPCC-1		1/10/11	2/24/11	
7.	Project 2007-07	Project 2007-07 - Vegetation Management - FAC-003	FAC-003-2		1/27/11	2/28/11	Yes 2/28/11
8.	N/A	CAN-0017--Draft CAN-0017 CIP-007 R5 System Access and Password Controls	CAN-0017 CIP-007, R5		2/11/11	3/4/11	Yes 3/4/11
9.	Project 2007-12	Project 2007-12 - Frequency Response	BAL-003-1		2/4/11	3/7/11	Yes 3/7/11
10.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002, IRO-001, and IRO-014	COM-001 COM-002 IRO-001 IRO-014		1/18/11	3/7/11	Yes 3/7/11
11.	NERC RoP	Proposed Changes to Rules of Procedure to Add Section 1700 - Challenges to Determinations	RoP Section 1700		2/14/11	3/7/11	Yes 3/7/11
12.	Project 2009-02	Project 2009-02 - Real-time Reliability Monitoring and Analysis Capabilities	Concept White Paper		2/16/11	4/4/11	Yes 4/4/11

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
13.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR Standards		3/4/11	4/4/11	Yes 4/4/11
14.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		3/9/11	4/8/11	Yes 4/8/11
15.	RFC RoP	Notice of Proposed Changes to RFC Rules of Procedure and Request for Comments			3/1/11	4/15/11	
16.	NERC RoP	Proposed Amendments to NERC Rules of Procedure Appendices 3B and 3D	Appendices 3B and 3D		3/1/11	4/15/11	Yes 4/15/11
17.	Project 2010-15	Project 2010-15 - Urgent Action Revisions to CIP-005-3 - CIP-005	CIP-005		3/29/11	4/28/11	Yes 4/27/11
18.	Project 2009-06	Project 2009-06 - Facility Ratings - FAC-008 and FAC-009	FAC-008-3		3/17/11	5/2/11	Yes 5/2/11
19.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		4/13/11	5/12/11	Yes 5/9/11
20.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition		4/28/11	5/27/11	Yes 5/27/11
21.	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs	TPL-001-2		4/18/11	5/31/11	Yes 5/31/11
22.	Project 2007-03	Project 2007-03 - Real-time Operations - TOP-001 through TOP-008 and PER-001	TOP-001 through TOP-008 and PER-001		4/26/11	6/9/11	Yes 6/9/11
23.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition		5/11/11	6/10/11	Yes 6/10/11
24.	NERC RoP	Rules of Procedure Development Team: BES Definition Exception Process	BES Definition Exception Process		5/11/11	6/10/11	Yes 6/10/11
25.	N/A	CAN-0024--Draft CAN-0024 CIP-002 through CIP-009 Routable Protocols and Data Diodes	CAN-0024 CIP-002 through CIP-009		5/20/11	6/10/11	

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
26.	N/A	CAN-0029--Draft CAN-0029 PRC-004-1 R1, R2 and R3 Misoperations	CAN-0029 PRC-004-1 R1, R2 and R3		5/20/11	6/10/11	
27.	N/A	CAN-0030--Draft CAN-0030 Attestations	CAN-0030 Attestations		5/20/11	6/10/11	
28.	N/A	CAN-0039--Draft CAN-0039 DOE Form 407	CAN-0039 DOE Form 407		5/20/11	6/10/11	
29.	Project 2010-05.1	Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)			6/10/11	7/11/11	
30.	Project 2007-09	Project 2007-09 – Generator Verification – MOD-025-2, MOD-027-1, PRC-019-1	MOD-025-2 MOD-027-1 PRC-019-1		6/15/11	7/15/11	Yes 7/15/11
31.	Project 2010-07	Project 2010-07 – Generator Requirements at the Transmission Interface – Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR standards	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR standards		6/17/11	7/17/11	Yes 7/15/11
32.	Project 2007-09	Project 2007-09 – Generator Verification – MOD-026-1 and PRC-024-1	MOD-026-1 and PRC-024-1		6/15/11	8/1/11	Yes 8/1/11
33.	NERC RoP	Proposed Changes to NERC Rules of Procedure and associated Appendices (Appendix 4B – Sanction Guidelines; and Appendix 4C – Compliance Monitoring and Enforcement Program)	Appendices 4B and 4C		6/30/11	8/15/11	
34.	N/A	Compliance Application Notice (CAN) Process	CAN Process		8/15/11	9/6/11	Yes 9/6/11
35..	N/A	CAN-0016 CIP-001 R1 - Sabotage Reporting Procedure	CAN-0016 CIP-001, R1		8/15/11	9/6/11	Yes 9/6/11
36.	N/A	DRAFT CANs Posted for Comment and Retirement of CAN-0001 through 0004	CAN-0001 through 0004 Retirement		8/31/11	9/21/11	

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
37.	NERC RSDP	NERC 2012-2014 Reliability Standards Development Plan	2012-2014 RSDP		9/12/11	9/26/11	Yes 9/26/11
38.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		8/15/11	9/28/11	Yes 9/28/11
39.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System - Initial Ballot of Definition of BES	BES Definition		8/26/11	10/10/11	Yes 10/10/11
40.	Project 2010-17	Project 2010-17 - Bulk Electric System (BES) Definition - Technical Principles for Demonstrating BES Exceptions	Technical Principles for Demonstrating BES Exceptions		8/26/11	10/10/11	Yes 10/10/11
41.	N/A	New CAN Template, five DRAFT CANs for Industry review and CANs Status posted to NERC Compliance's Web site.	CANs		9/23/11	10/14/11	Yes 10/14/11
42.	RoP	Proposed Changes to NERC Rules of Procedure and All Appendices			9/2/11	10/17/11	
43.	Project 2010-17	Project 2010-17 - Bulk Electric System (BES) Definition - Rules of procedure Modifications to Support BES Exception Requests	RoP Section 509, Section 1703 and Appendix 5C		9/13/11	10/27/11	Yes 10/27/11
44.	N/A	CAN-0010--Definition of "Annual" and Implementation of Annual Requirements	CAN-0010 Definition of Annual		10/10/11	10/31/11	Yes 10/31/11
45.	N/A	CAN-0011--PRC-005-1 R2: New Equipment	CAN-0011 PRC-005-1 R2		10/10/11	10/31/11	Yes 10/31/11
46.	N/A	CAN-0012--Completion of Periodic Activity Requirements During Implementation Plan	CAN-0012 Completion of Periodic Activity Requirements		10/10/11	10/31/11	Yes 10/31/11
47	N/A	CAN-0013--PRC-023 R1 and R2 Effective Dates for Switch-on-to-Fault Schemes	CAN-0013 PRC-023 R1 and R2		10/10/11	10/31/11	
48.	N/A	CAN-0015--Unavailability of NERC Software Tools	CAN-0015 NERC Tools		10/10/11	10/31/11	Yes 10/31/11

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49.	N/A	CAN-0022--VAR-002-1.1b R1 and R3 Generator Operation in Manual Mode	CAN-0022 VAR-002-1.1b R1 and R3		10/10/11	10/31/11	
50.	N/A	CAN-0024--CIP-002 R3 Routable Protocols and Data Diode Devices	CAN-0024 CIP-002, R3		10/10/11	10/31/11	Yes 10/31/11
51.	N/A	CAN-0026--TOP-006 R3 Protection Relays	CAN-0026 TOP-006, R3		10/10/11	10/31/11	Yes 10/31/11
52.	N/A	CAN-0028--TOP-006-1 R1.2 Reporting Responsibilities	CAN-0028 TOP-006-1, R1.2		10/10/11	10/31/11	
53.	N/A	CAN-0020--TPL-002, TPL-003, TPL-004 and TOP-002 Equipment Maintenance Outages	CAN-0020 TPL-002, TPL-003, TPL-004 and TOP-002		10/19/11	11/9/11	
54.	N/A	CAN-0030--Attestations	CAN-0030		10/19/11	11/9/11	
55.	Project 2011-INT-01	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	MOD-028, R3.1		10/3/11	11/16/11	Yes 11/16/11
56.	Project 2009-22	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Interpretation of COM-002-2, R2		10/4/11	11/18/11	Yes 11/18/11
57.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR Standards		10/5/11	11/18/11	Yes 11/18/11
58.	N/A	Draft Directive Regarding Generator Transmission Leads	Draft Directive #2011 CAG-001		10/17/11	11/18/11	Yes 11/18/11
59.	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-1 R1.1 by Progress Energy	Interpretation of CIP-006-1, R1.1		10/12/11	11/21/11	Yes 11/21/11
60.	N/A	CAN-0040 - BAL-003 Frequency Bias Calculation			11/2/11	11/23/11	
61.	N/A	CAN-0043 - PRC-005 Protection System Maintenance and Testing Evidence	PRC-005 Evidence		11/2/11	11/23/11	Yes 11/22/11
62.	Project 2007-12	Project 2007-12 - Frequency Response	BAL-003-1			12/8/11	Yes 12/8/11
63.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2			12/12/11	Yes 12/12/11

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64.	N/A	Draft CAN-0027: TOP-003 R2 Coordination of Scheduled Outages	CAN-0027 TOP-003, R2		11/22/11	12/14/11	
65.	NERC RoP	Proposed Changes to the NERC Rules of Procedure and Associated Appendices			11/7/11	12/22/11	
66.	NERC RoP	Notice of Revisions to Proposed New Sections 1.1.24 and 5.11 of Appendix 4C of the NERC Rules of Procedure, as Originally Posted for Comment on November 7, 2011			11/22/11	12/22/11	
67.	Regional Standard	Regional Reliability Standard PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding	PRC-006-NPCC-1		11/22/11	12/22/11	
68.	Project 2008-06	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1 (Version 5 CIP Standards)	Version 5 CIP Standards		11/7/11	1/6/12	Yes 1/6/12
69.	Project 2007-03	Project 2007-03 - Real-time Transmission Operations - TOP-001-2, TOP-002-3 and TOP-003-2	TOP-001-2 TOP-002-3 TOP-003-2		12/14/11	1/12/12	Yes 1/12/12
70.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	BES Definition, Phase 2		1/4/12	2/3/12	Yes 2/3/12
71.	N/A	Order 754 - Request for Data or Information	Data Request		12/22/11	2/6/12	Yes 2/6/12
72.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002 and IRO-001-3	COM-001 COM-002 IRO-001-3		1/9/12	2/9/12	Yes 2/8/12
73.	WECC Regional Standard	Regional Reliability Standard BAL-004-WECC-02 - Automatic Time Error Correction	BAL-004-WECC-02		1/23/12	3/9/12	

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74.	WECC Regional Standard	Regional Reliability Standard BAL-001-0.1a - Real Power Balancing Control Performance - WECC Variance	BAL-001-0.1a		1/23/12	3/9/12	
75.	N/A	NERC Functional Model Demand Response Functions and Entities	NERC Functional Model		2/13/12	3/14/12	
76.	Project 2009-26	Project 2009-26 - Interpretation of CIP-004-1 for WECC	Interpretation of CIP-004-1		2/8/12	3/23/12	Yes 3/23/12
77.	Project 2010-INT-05	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy	Interpretation of CIP-002-1, R3		2/8/12	3/23/12	Yes 3/23/12
78.	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR -002 for Constellation	Interpretation of VAR -002		2/8/12	3/23/12	Yes 3/23/12
79.	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing - PRC-005	PRC-005-2		2/28/12	3/28/12	Yes 3/28/12
80.	Project 2007-09	Project 2007-09 Generator Verification - MOD-026-1 and PRC-024-1	MOD-026-1 and PRC-024-1		2/29/12	3/29/12	Yes 3/29/12
81.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface - FAC-003-X, FAC-003-3	FAC-003-X FAC-003-3		3/9/12	4/9/12	Yes 4/9/12
82.	Project 2007-09	Project 2007-09 Generator Verification - MOD-025-2, MOD-027-1, and PRC-019-1	MOD-025-2 MOD-027-1 PRC-019-1		2/29/12	4/16/12	Yes 4/16/12
83.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface - PRC-005-1.1a	PRC-005-1.1a		3/2/12	4/16/12	Yes 4/16/12
84.	Project 2007-03	Project 2007-03 - Real-time Transmission Operations	TOP-001 through TOP-008 and PER-001		3/22/12	4/20/12	Yes 4/20/12
85.	Project 2012-INT-02	Request for Interpretation - Project 2012-INT-02 TPL-003-0a and TPL-004-0 for SPCS	Interpretation of TPL-003-0a and TPL-004-0		4/24/12	5/4/12	

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86.	Project 2008-06	Project 2008-06 - Cyber Security Order 706 Version 5 CIP	CIP-002 and CIP-003 - Comment Form A		4/12/12	5/21/12	Yes 5/20/12
			CIP-004 thru CIP-007 - Comment Form B		4/12/12	5/21/12	Yes 5/20/12
			CIP-008 thru CIP-011 - Comment Form C		4/12/12	5/21/12	Yes 5/20/12
			Definitions and Implementation Plan - Comment Form D		4/12/12	5/21/12	Yes 5/20/12
87.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		4/25/12	5/24/12	Yes 5/24/12
88.	Project 2007-12	Project 2007-12 Frequency Response Technical Conferences			5/30/12	6/15/12	
89.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	COM-003		5/7/12	6/20/12	Yes 6/20/12
90.	N/A	Adequate Level of Reliability Revised Definition and Associated Documents	Adequate Level of Reliability (ALR)		4/25/12	6/25/12	Yes 6/25/12
91.	N/A	Order 754 - Request for Data or Information	Data Request		5/11/12	6/25/12	Yes 6/25/12
92.	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR - 002 for Constellation	Interpretation of VAR -002		5/22/12	6/27/12	Yes 6/27/12
93.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		5/29/12	6/27/12	Yes 6/27/12
94.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserve	BAL-001-1		6/4/12	7/3/12	Yes 7/3/12
			BAL-002-2		6/4/12	7/3/12	Yes 7/3/12
			BAL-012-1		6/4/12	7/3/12	Yes 7/3/12
			BAL-013-1		6/4/12	7/3/12	Yes 7/3/12
95.	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-001 and PRC-027		5/21/12	7/5/12	Yes 7/5/12

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96.	N/A	Cost Effective Analysis Process (CEAP) for NERC ERO Standards	CEAP		5/7/12	7/6/12	Yes 7/6/12
97.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002 and IRO-001-3	COM-001, COM-002 and IRO-001-3		6/7/12	7/6/12	Yes 7/6/12
98.	Project 2006-02	Project 2006-02 – Assess Transmission Future Needs and Develop Transmission Plans	TPL-002-1b, footnote 'b' and TPL-001-3, footnote 12		6/19/12	7/9/12	Yes 7/9/12
99.	N/A	Standard Processes Manual Revisions to Implement SPIG Recommendations	SPIG Reco		6/20/12	7/19/12	Yes 7/19/12
100.	Project 2012-INT-02	Project 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for System Protection and Control Subcommittee	- Interpretation of TPL-003-0a and TPL-004-0		6/20/12	7/20/12	Yes 7/19/12
101.	Project 2012-INT-05	Interpretation of 2012-INT-05 - Interpretation of CIP-002-3 for OGE	Interpretation of CIP-002-3		6/27/12	7/27/12	Yes 7/27/12
102.	Project 2011-INT-02	Project 2011-INT-02 - Rapid Revision to Address Interpretation of VAR-002 for Constellation	Rapid Revision to VAR-002		7/18/12	7/27/12	Yes 7/26/12
103.	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Rapid Revision of TOP-006		6/14/12	7/30/12	Yes 7/27/12
104.	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Glossary of Terms		6/19/12	8/2/12	Yes 8/2/12
105.	N/A	Reliability Guideline: System Operator Verbal Communications – Current Industry Practices	System Operator Verbal Communications		6/26/12	8/10/12	Yes 8/9/12
106.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		7/27/12	8/27/12	Yes 8/27/12

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107.	Project 2010-11	Project 2010-11 - TPL Table 1 Order TPL-002-1b, footnote 'b' and TPL-001-3, footnote 12	TPL-002-1b, footnote 'b' and TPL-001-3, footnote 12		7/31/12	8/29/12	Yes 8/29/12
108.	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs			7/31/12	8/30/12	
109.	Project 2009-19	Project 2009-19 – Interpretation of BAL-002 by NWPP Reserve Sharing Group			7/25/12	9/4/12	
110.	Project 2013-02	Project 2013-02 - Paragraph 81	Paragraph 81		8/3/12	9/4/12	Yes 9/4/12
111.	Project 2010-05.1	Project 2010-05.1 - Protection Systems: Phase 1 (Misoperations)			7/25/12	9/7/12	Yes 9/7/12
112.	N/A	Definition of Adequate Level of Reliability	Adequate Level of Reliability (ALR)		8/15/12	9/13/12	Yes 9/13/12
113.	N/A	2013-2015 Reliability Standards Development Plan	2013-2015 RSDP		8/17/12	9/18/12	Yes 9/18/12
114.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols	COM-003-1		8/22/12	9/20/12	Yes 9/20/12
115.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		8/29/12	9/27/12	
116.	SPP Regional Standard	Regional Reliability Standard PRC-006-SPP-01 Automatic Underfrequency Load Shedding	PRC-006-SPP-01		8/15/12	9/28/12	
117.	Project 2008-06 Project 2008-06	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1	Version 5 CIP Standards		9/11/12	10/10/12	Yes 10/10/12
			RSAW		9/11/12	10/10/12	Yes 10/10/12
118.	MRO SPM	Regional Reliability Standards - MRO Standards Process Manual			8/28/12	10/11/12	
119.	N/A	Standard Process Manual Revisions to Implement SPIG Recommendations	SPIG Reco		8/29/12	10/12/12	Yes 10/10/12
120.		Revisions to Outstanding VRFs and VSLs			9/5/12	10/19/12	

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121.	Project 2013-01	Project 2013-01 - Cold Weather Preparedness			9/25/12	10/24/12	
122.	Project 2007-09	Project 2007-09 - Generator Verification			9/28/12	10/29/12	
123.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System			10/4/12	11/5/12	
124.	2007-12	Project 2007-12 - Frequency Response			10/5/12	11/7/12	
125.	Project 2008-06	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1	Version 5 CIP Standards		10/26/12	11/7/12	
126.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	PRC-025		10/5/12	11/7/12	
127.	N/A	IRO-006-WECC-2			10/3/12	11/16/12	
128.	Project 2010-11	Project 2010-11 - TPL Table 1, Footnote B			10/5/12	11/19/12	
129.	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Interpretation of TPL-003-0a and TPL-004-0		10/22/12	12/5/12	Yes 12/5/12
130.	Project 2013-02	Project 2013-02 - Paragraph 81	Paragraph 81		10/25/12	12/10/12	Yes 12/10/12
131.	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	- Interpretation of CIP-003-3		11/9/12	12/10/12	Yes 12/10/12
132.	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	- Interpretation of CIP-007-3		11/9/12	12/10/12	Yes 12/10/12
133.	Project 2007-02	Project 2007-02 - Operating Personnel Communication Protocols - RSAW	COM-003-1		11/14/12	12/13/12	Yes 12/13/12
			COM-003-1 RSAW		11/14/12	12/13/12	Yes 12/13/12
134.	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-001 and PRC-027		11/16/12	12/17/12	Yes 12/17/12
135.	Project 2012-INT-05	Project 2012-INT-05 - Interpretation of CIP-002-3 for OGE	Interpretation of CIP-002-3		11/6/12	12/20/12	Yes 12/20/12
136.	N/A	Standard Processes Manual to Implement SPIG Revisions	SPIG Reco		11/21/12	12/20/12	Yes 12/20/12
137.	Project 2010-11	Project 2010-11 - TPL Table 1, Footnote B	TPL-002-1b, footnote 'b' and TPL-001-3, footnote 12		12/10/12	1/11/13	Yes 1/11/13

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138.	Project 2007-09	Project 2007-09 - Generator Verification - PRC-024-1	PRC-024-1		12/12/12	1/11/13	Yes 1/11/13
139.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-012-1	BAL-012-1		11/30/12	1/14/13	Yes 1/14/13
140.	N/A	Reliability Guideline--Draft Generating Unit Winter Weather Readiness - Current Industry Practices			12/20/12	2/4/13	Yes 2/4/13
141.	Project 2010-05-1	Project 2010-05-1 Protection System Misoperations					Yes 2/20/13
142.	Project 2007-09	Project 2007-09 Generator Verification - PRC-024-1	PRC-024-1	Formal	1/25/13	2/25/13	Yes 2/25/13
143.	N/A	Rapid Revision Procedure		Informal	2/25/13	3/6/13	Yes 3/6/13
144.	Project 2010-13-2	Project 2010-13-2 - Phase 2 of Relay Loadability - Generation - PRC-025-1	PRC-025-1	Formal	1/25/13	3/11/13	Yes 3/11/13
			Supplemental SAR	Informal	1/25/13	3/11/13	Yes 3/11/13
			Cost Effectiveness	CEAP Pilot	1/25/13	3/11/13	Yes 3/11/13
			RSAW	Feedback	1/25/13	3/11/13	Yes 3/11/13
145.	Project 2012-INT-04	Interpretation 2012-INT-04 - Interpretation of CIP-007 for ITC	Interpretation of CIP-007	Formal	2/6/13	3/22/13	Yes 3/22/13
146.	Project 2012-INT-06	Interpretation 2012-INT-06 - Interpretation of CIP-003 for Consumers Energy	Interpretation of CIP-003	Formal	2/6/13	3/22/13	Yes 3/22/13
147.	Project 2012-08-1	Project 2012-08-1 - Phase 1 of Glossary Updates--Statutory Definitions	Glossary of Terms	Formal	2/21/13	3/22/13	Yes 3/22/13
148.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003-1	COM-003-1	Formal	3/7/13	4/5/13	Yes 4/5/13
			RSAW	Feedback	3/7/13	4/5/13	Yes 4/5/13
149.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves	BAL-001-2	Formal	3/12/13	4/25/13	Yes 4/25/13
			BAL-002-2	Formal	3/12/13	4/25/13	Yes 4/25/13
			BAL-013-1	Formal	3/12/13	4/25/13	Yes 4/25/13

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150.	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays)	Draft SAR	Informal	4/5/13	5/6/13	Yes 5/6/13
			PRC-005-3	Formal	4/5/13	5/6/13	Yes 5/613
151.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation	PRC-023-3 PRC-025-1	Formal	4/25/13	5/24/13	Yes 5/24/13
152.	Project 2007-11	Project 2007-11 - Disturbance Monitoring — PRC-002 and PRC-018	SAR	Informal	5/03/13	6/03/13	Yes 6/3/13
153.	Project 2007-11	Project 2007-11 - Disturbance Monitoring PRC-002 and PRC-018	Request for Information	Informal	6/05/13	7/05/13	
154.	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	PRC-001 and PRC-027		6/04/13	7/03/13	Yes 7/03/13
155.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	BES Definition		5/29/13	7/12/13	Yes 7/12/13
156.	TRE Regional Standard	Regional Reliability Standard - BAL-001-TRE-01	BAL-001-TRE-01		5/31/13	7/15/13	
157.	N/A	NPCC Regional Standards Process Manual	NPCC RSPM		6/06/13	7/22/13	
158.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	COM-003-1		6/20/13	7/19/13	Yes 7/19/13
159.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	PRC-025-1		6/20/13	7/19/13	Yes 7/19/13
160.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023	PRC-023-3	Formal	6/20/13	8/05/13	Yes 8/5/13
161.	N/A	SPP RE Regional Standards Process Manual	SPP RSPM		6/26/13	8/09/13	
162.	Project 2013-03	Project 2013-03 - Geomagnetic Disturbance Mitigation	EOP-010-1	Formal	6/27/13	8/12/13	Yes 8/12/13

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163.	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005	PRC-005-3	Formal	7/10/13	8/23/13	Yes 8/23/13
164.	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards	INT-004-3 INT-006-4 INT-009-2 INT-010-2 INT-011-1	Informal	7/25/13	8/23/13	Yes 8/23/13
165.	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	MOD-001-2	Formal	7/11/13	8/26/13	Yes 8/26/13
166.	Project 2010-01	Project 2010-01 - Training - PER-005-2	PER-005-2	Formal	7/19/13	9/03/13	Yes 9/3/13
167.	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	VAR-001-4 VAR-002-3	Formal	7/19/13	9/03/13	Yes 9/3/13
168	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	MOD-032-1 MOD-033-1	Formal	7/22/13	9/04/13	Yes 9/4/13
169.	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	MOD-031-1	Formal	7/22/13	9/04/13	Yes 9/4/13
170	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System – Phase 2	BES Definition Phase 2	Formal	8/6/13	9/4/13	Yes 9/4/13
171	Project 2012-13	Project 2012-13 - NUC Five-Year Review	NUC-001-2	5-year review	7/26/13	9/9/13	Yes 9/9/13
172	2014-2016 RSDP	2014-2016 Reliability Standards Development Plan	Reliability Standards Development Plan	Annual Review	8/30/13	9/13/13	Yes 9/13/13
173	Project 2010-02	Project 2010-02 Five-Year Review of FAC Standards	FAC-001-1 FAC-002-1	5-year review	8/1/13	9/16/13	Yes 9/16/13
174	Project 2010-02	Project 2010-02 Five-Year Review of FAC Standards	FAC-003-3 FAC-008-3 FAC-010-2.1 FAC-011-2 FAC-013-2 FAC-014-2	5-year review	8/1/13	9/16/13	Yes 9/16/13
175	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2, BAL-013-1	BAL-002-2	Formal	8/2/13	9/16/13	Yes 9/16/13

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176	Project 2009-03	Project 2009-03 — Five-Year Review of Emergency Operations EOP-001, EOP-002, EOP-003, and IRO-001	EOP-001-2.1b EOP-002-3.1 EOP-003-2	5-year review	8/6/13	9/19/13	Yes 9/19/13
177	Project 2012-09	Project 2012-09 IRO Five-Year Review	IRO-003-2 IRO-004-2 IRO-005-4 IRO-006-5 IRO-006-East IRO-008-1 IRO-009-1 IRO-010-1a	5-year review	8/7/13	9/20/13	Yes 9/20/13
178	Project 2008-02	Project 2008-02 Undervoltage Load Shedding	Revised SAR	Informal	9/10/13	10/9/13	Yes 10/9/13
179	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	EOP-010-1	Formal	9/4/13	10/18/13	Yes 10/18/13
180	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition	Formal	9/27/13	10/28/13	Yes 10/28/13
181	Project 2007-02	Project 2007-02 Operating Personnel Communications Protocols	COM-002-4	Formal	10/21/13	11/7/13	Yes 11/4/13
182	Project 2010-01	Project 2010-01 Training	PER-005-2	Formal	9/27/13	11/12/13	Yes 11/12/13
183	Project 2008-12	Project 2008-12 Coordinate Interchange Standards	Various INT Standards	Formal	9/30/13	11/13/13	Yes 11/13/13
184	Project 2012-05	Project 2012-05 ATC Revisions (MOD A)	MOD-001-2	Formal	10/4/13	11/20/13	Yes 11/18/13
185	Project 2010-03	Project 2010-03 Modeling Data (MOD B)	MOD-032-1, MOD-033-1	Formal	10/07/13	11/20/13	
186	Project 2010-04	Project 2010-04 Demand Data (MOD C)	MOD-031-1	Formal	10/09/13	11/22/13	Yes 11/22/13
187	Project 2013-04	Project 2013-04 Voltage and Reactive Control	VAR-001-4, VAR-002-3	Formal	10/11/13	11/25/13	Yes 11/25/13
188	Project 2009-03	Project 2009-03 Emergency Operations	SAR	Informal	11/06/13	12/05/13	Yes 12/5/13
189	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves	BAL-002-2	Formal	10/28/13	12/11/13	Yes 12/11/13
190	Project 2007-11	Project 2007-11 - Disturbance Monitoring	PRC-002-2	Formal	11/01/13	12/16/13	Yes 12/16/13

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
191	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-027	Formal	11/04/13	12/18/13	Yes 12/18/13
192	Project 2014-01	Project 2014-01 - Standards Applicability for Dispersed Generation Resources	SAR	Formal	11/20/13	12/19/13	Yes 12/19/13
193	Project 2010-01	Project 2010-01 Training - PER-005-2	PER-005-2	Formal	12/4/13	1/22/14	Yes 1/17/14
194	Project 2010-03	Project 2010-03 Modeling Date - MOD B	MOD-033-1	Formal	12/6/13	1/22/14	Yes 1/21/14
195	Project 2008-12	Project 2008-12 Coordinate Interchange Standards	INT-004-3 INT-010-2	Formal	1/10/14	1/24/14	Yes 1/22/14
196	Project 2007-02	Project 2007-02 Operating Personnel	COM-002-4	Formal	1/22/14	1/31/14	Yes 1/31/14
197	Project 2014-02	Project 2014-02 Standard Authorization Request – Cyber Security Standards	CIP SAR	Informal	1/17/14	2/18/14	Yes 2/18/14
198	2014 Work Plan	2014 Work Plan for NERC Reliability Standards Development	2014 Work plan			2/21/13	Yes 2/21/14
199	Project 2010-17	Project 2010-17 Definition of Bulk Electric System - Phase 2	BES	Informal	1/29/14	2/27/14	Yes 2/27/14
200	Project 2010-05.1	Project 2010-05.1 Protection System: Phase 1 (Misoperations) - PRC-004-3	PRC-004-3	Formal	1/17/14	3/11/14	Yes 3/2/14
201	Project 2012-13	Project 2012-13 NUC-Nuclear Plant Interface Coordination Standard Authorization Request	NUC-001-2.1 SAR	Informal	2/12/14	3/13/14	Yes 3/13/14
202	Project 2010-05.2	Project 2010-05.2 Special Protection Systems (Phase 2 of Protection Systems) - SAR	SAR	Informal	2/18/14	3/19/14	Yes 3/19/14
203	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	SAR	Formal	02/21/14	03/24/14	Yes 3/24/14
204	Project 2014-03	Technical Conferences on Revisions to TOP/IRO Reliability Standards	Technical Conference Topics	Informal	03/11/14	03/24/14	
205	Project 2014-04	Project 2014-04 - Physical Security	SAR	Informal	03/21/14	03/28/14	Yes 3/28/14

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
206	Project 2010-14.2	Project 2010-14.2 - Periodic Review of BAL Standards	Reco to Revise BAL-005 and BAL-006	Formal	02/21/14	04/07/14	
207	2010-05.2	Project 2010-05.2 - Phase 2 of Protection Systems - Revised Definition of Special Protection System	SPS Definition	Informal	03/11/14	04/09/14	Yes 4/9/14
208	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	MOD-031-1	Formal	02/25/14	04/10/14	Yes 4/10/14
209	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	VAR-002-3	Formal	02/27/14	04/14/14	Yes 4/14/14
210	Project 2008-02	Project 2008-02 - Undervoltage Load Shedding - PRC-010, PRC-020, PRC-021 and PRC-022	PRC-010-1	Informal	03/17/14	04/16/14	Yes 4/16/14
211	Project 2014-04	Project 2014-04 Physical Security - CIP-014-1	CIP-014-1	Formal	04/10/14	04/24/14	Yes 4/24/14
212	Project 2009-03	Project 2009-03 Emergency Operations – EOP-011-1	EOP-011-1	Informal	03/28/14	04/28/14	Yes 4/28/14
213	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-005-2(X) PRC-005-3(X) PRC-005-X(X) VAR-002-2b(X) VAR-002-4	Formal	04/17/14	05/05/14	Yes 5/5/14
214	Project 2010-02	Project 2010-02 – Connecting New Facilities to the Grid	FAC-001-1 FAC-002-1	Formal	04/01/14	05/15/14	Yes 5/15/14
215	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	TPL-007-1	Informal	04/22/14	05/21/14	Yes 5/21/14
216	Project 2012-13	Project 2012-13 Nuclear Plant Interface Coordination	NUC-001-3	Formal	04/08/14	05/22/14	Yes 5/22/14
217	Project 2007-17.3	Project 2007-17.3 Protection System Maintenance and Testing – Phase 3 (Sudden Pressure Relays)	PRC-005-X	Formal	04/17/14	06/03/14	Yes 6/3/14
218	Project 2010-13.3	Project 2010-13.3 Relay Loadability: Stable Power Swings	PRC-026-1	Formal	04/25/14	06/09/14	Yes 6/9/14
219	Project 2007-11	Project 2007-11 Disturbance Monitoring	PRC-002-2	Formal	05/09/14	06/25/14	Yes 6/25/14

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
221	Project 2008-02	Project 2008-02 Undervoltage Load Shedding and Underfrequency Load Shedding	PRC-010 PRC-020 PRC-021 PRC-022	Informal	05/23/14	06/23/14	Yes 6/23/14
222	Project 2010-05-1	Project 2010-05-1 Protection System – Phase 1 – Misoperations	PRC-004	Formal	05/16/14	07/09/14	Yes 7/9/14
223	Project 2014-03	Project 2014-03 Revisions to TOP-IRO Reliability Standards	TOP-001-3 TOP-002-4 TOP-003-3 IRO-001-4 IRO-002-4 IRO-008-2 IRO-010-2 IRO-014-3 IRO-017-1	Formal	05/19/14	07/02/14	Yes 7/2/14
224	Project 2014-02	Project 2014-02 CIP Version 5 Revisions – Cyber Security Standards	CIP-002 to CIP-011	Formal	06/02/14	07/17/14	Yes 7/16/14
225	Project 2015-2017	Project 2015-2017 Reliability Standard Development Plan		Informal		7/21/14	Yes 7/21/14
226	2010-05.2	Project 2010-05.2 - Phase 2 of Protection Systems - Revised Definition of Special Protection System	SPS Definition	Formal	7/16/14	7/25/14	Yes 7/25/14
227	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-005-2(X) PRC-005-3(X) PRC-005-X(X) VAR-002-2b(X) VAR-002-4	Formal	06/12/14	7/29/14	Yes 7/29/14
228	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	TPL-007-1	Formal	06/13/14	07/30/14	Yes 7/30/14
229	Project 2008-02	Project 2008-02 Undervoltage Load Shedding and Underfrequency Load Shedding	PRC-010 PRC-020 PRC-021 PRC-022	Formal	06/23/14	08/8/14	Yes 8/6/14
230	Project 2010-14-2	Project 2010-14-2 Balancing Authority Reliability-based Control Standard Authorization Request	BAL-005 BAL-006	Informal	07/16/14	08/14/14	Yes 8/12/14

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		for BAL-005 and BAL-006					
231	Project 2009-03	Project 2009-03 Emergency Operations – EOP-011-1	EOP-011-1	Formal	07/2/14	08/15/14	Yes 8/13/14
232	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-004-2.1a(X) PRC-004-3(X)	Formal	07/10/14	08/26/14	Yes 8/25/14
233	Project 2007-17.3	Project 2007-17.3 Protection System Maintenance and Testing – Phase 3 (Sudden Pressure Relays) – PRC-005-X	PRC-005-X	Formal	07/30/14	09/12/14	Yes 9/12/14
234	Project 2014-03	Project 2014-03 Revisions to TOP-IRO Reliability Standards	TOP-001-3 TOP-002-4 TOP-003-3 IRO-001-4 IRO-002-4 IRO-008-2 IRO-010-2 IRO-014-3 IRO-017-1	Formal	08/6/14	09/19/14	Yes 9/22/14
235	Project 2010-14.1	Project 2010-14.1 Balancing Authority Reliability-based Control	BAL-002-2	Formal	08/19/14	10/03/14	Yes 10/2/14
236	Project 2010-13.3	Project 2010-13.3 – Relay Loadability: Stable Power Swings	PRC-026-1	Formal	09/26/14	10/06/14	Yes 10/6/14
237	Project 2008-02	Project 2008-02: Underfrequency Load Shedding (UFLS)	PRC-006-2	Formal	08/21/14	10/08/14	Yes 10/7/14
238	Project 2013-03	Project 2013-03: Geomagnetic Disturbance Mitigation	TPL-007-1	Formal	08/27/14	10/10/14	Yes 10/10/14
239	NERC Rules of Procedure	NERC Rules of Procedure	NERC Rules of Procedure	Formal	08/26/14	10/10/14	Yes 10/14/14
240	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems Phase 2 of Protection Systems	RAS Definition	Formal	08/29/14	10/14/14	Yes 10/14/14
241	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	VAR-002-2b(X) VAR-002-4	Formal	08/27/14	10/16/14	Yes 10/16/14
242	Project 2014-02	Project 2014-02 CIP Version 5 Revisions – Cyber Security Standards	CIP-003-6 CIP-010-2 CIP-003-X CIP-004-X	Formal	09/03/14	10/17/14	Yes 10/17/14

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
			CIP-007-X CIP-010-X CIP-011-X				
243	Project 2009-03	Project 2009-03 Emergency Operations	EOP-011-1	Formal	09/05/14	10/20/14	Yes 10/20/14
244	Project 2007-06	Project 2007-06 System Protection Coordination PRC-027-1 (Preliminary Draft 5)	PRC-027-1	Informal	10/01/14	10/21/14	Yes 10/21/14
245	Project 2007-11	Project 2007-11 Disturbance Monitoring	PRC-002-2	Formal	09/05/14	10/21/14	Yes 10/21/14
246	Project 2014-01	Project 2014-01 Applicability for Dispersed Generation	PRC-004-2.1a(X) PRC-004-4	Formal	09/05/14	10/22/14	Yes 10/22/14
247	Project 2014-03	Project 2014-03 Revisions to TOP/IRO Reliability Standards TOP-001-3	TOP-001-3	Formal	10/10/14	11/10/14	Yes 11/10/14
248	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-1	TPL-007-1	Formal	10/28/14	11/21/14	Yes 11/24/14
249	Project 2010-13.3	Project 2010-13.3 – Relay Loadability: Stable Power Swings	PRC-026-1	Formal	11/04/14	11/24/14	Yes 11/25/14
250	Project 2014-01	Project 2014-01 – Standards Applicability for Dispersed Generation Resources	PRC-001-1.1 PRC-019-2 PRC-024-1	Formal	11/05/14	12/23/14	Yes 12/22/14
251	Project 2014-03	Project 2014-03 Revisions to TOP/IRO Reliability Standards TOP-001-3	TOP-001-3	Formal	12/29/14	1/7/15	Yes 1/6/15
252	Project 2014-02	Project 2014-02 CIP Version 5 Revisions	CIP-003-7 CIP-004-7 CIP-007-7 CIP-010-3 CIP-011-3 CIP-003-7 CIP-010-3 Implementation Plan	Formal	12/30/14	1/9/15	Yes 1/9/15
253	Project 2014-04	Project 2014-04 Physical Security SAR	SAR	Informal	12/15/14	1/13/15	Yes 1/12/15
254	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	White Paper Appendix A Appendix B	Informal	12/22/14	1/20/15	Yes 1/20/15

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
255	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-005-5	Informal	12/22/14	1/20/15	Yes 1/22/15
257	Project 2010-14.1	Project 2010-14.1 Balancing Authority Reliability-based Control	BAL-002-2	Formal	1/29/15	3/18/15	Yes 3/16/15
258	Reliability Guideline	Reliability Guideline: Loss of Real-Time Reliability Tools Capability/Loss of Equipment Significantly Affecting ICCP Data		Formal	2/19/15	4/6/15	Yes 4/6/15
259	Project 2008-02.2	Project 2008-02.2 Phase 2 UVLS: Misoperation	PRC-010	Formal	2/20/15	4/7/15	Yes 4/7/15
260	Project 2014-04	Project 2014-04 Physical Security	CIP-014-2	Formal	2/20/15	4/9/15	Yes 4/9/15

Note: RSC past comment forms are posted on the NPCC Website under "Standards - Regional Standards Comments."

PRC-002-NPCC-02 Disturbance Monitoring Draft Team Roster

Name:	Company:	Qualifications:
Don Burkart	Con Edison	Don has 5 years in relay protection engineering and have had countless experiences in system event analyses. Additionally, He is the Lead Disciple Engineer for the company wide DME programs.
Robert Grabovickic	National Grid	Responsibilities include the analysis of events and system disturbances, protection co-ordination studies, calculations of settings for protection relays and disturbance fault recorders (DFRs), configuration of DFRs for NY PMU project, reviewing the relay settings of generators owned by customers, the development of protection standards.
Tim Kucey	PSEG	Member of current NPCC PRC-002-NPCC review SDT (joined SDT in 2013 in response to membership solicitation). Co-lead of the "Tools and Training" team of the NERC investigation of the August 2003 Northeast Blackout. Responsible for the bulk of the team's findings/discoveries – and the associated write-ups in the NERC and US-Canada Bilateral Commission reports - regarding key entities' implementation, usage and the performance of system monitoring and analysis "tools" (e.g. EMS, RTCAs, SEs) involved in the incident. For the period 1994 through to 2002, technical positions with process and power industry DCS/EMS, SCADA and RTU OEMs: Fisher-Rosemount (now Emerson); Moore Process Control (now Siemens); GE Harris (previously Westronics, HDAP; now GE Power). NERC Manager of Enforcement and Mitigation from 2006 until 2010, then NERC's CEA agent (Manager of NOP Development) until late 2011. Duties included review of all compliance actions taken by NERC to the NERC BOT Compliance Committee, frequent engagement with the CCC and the Standards Committee, FERC staff, SDTs. Also involvement in several NERC events analyses/investigations and joint NERC-FERC 1B actions, typically involving transmission organizations, balancing authorities and reliability coordinators.
Brian Evans-Mongeon	Utility Services	As a prior member of the drafting team, he believe that he is qualified to serve again. He has been involved in numerous drafting teams including EOP-004, PRC-006 for both NPCC and NERC, BES, and Dispersed Generating Resources. He also serve on the NPCC RCC and the NERC PC, ERSTF, and RBRTF.
Robert Pellegrini	UI	Involved in designing P&C SCADA systems
Jim Watson	Dynergy	He has been employed in the electric utility industry for 33 years in the areas of generation operations, planning, and environmental compliance and for the last 4 years – NERC compliance.
George Wegh	Eversource	George has over 25 years of Electrical Engineering experience, of which 15 years have been in the utility industry. He is presently the Manager of Transmission Protection and Controls Engineering at Eversource Energy. He has been working in the Transmission Protection and Controls Department at Eversource Energy for over 8 years. He presently serve as the NPCC representative on the NERC System Protection and Controls Subcommittee (SPCS) and am Vice Chairman of the NPCC Task Force on System Protection (TFSP).
Paul Difilippo	Hydro One	28 years of experience in various aspects of protection systems at Hydro One including analysis of the 2003 Northeast blackout utilizing all available DME in Ontario. Member of TFSP since 2008 and current Chair. He is also the requester for the RSAR.
RuiDa Shu	NPCC	NPCC Standards Staff

Lee Pedowicz	NPCC	Manager of Reliability Standards
	NPCC	NPCC Compliance Staff

Information in a Regional Standard Authorization Request (RSAR)

The tables below identify information to be submitted in a Regional Standard Authorization Request to the NPCC Regional Standards Process Manager, NPCCstandard@npcc.org . The NPCC Regional Standards Process Manager shall be responsible for implementing and maintaining this form as needed to support the information requirements of the standards process.

Regional Standard Authorization Request Form

Title of Proposed Standard:	PRC-002-NPCC-02 – Disturbance Monitoring
Request Date:	Nov. 26, 2012

RSAR Requester Information

		RSAR Type (Check box for one of these selections.)	
Name:	**Daren Verner**		
Company:	Task Force on System Protection	☐	New Standard
Telephone:	506-458-3361	☒	Revision to Existing Standard
Fax:		☐	Withdrawal of Existing Standard
Email:	dverner@nbpower.com	☐	Urgent Action

Purpose (Describe the purpose of the proposed standard – what the standard will achieve in support of reliability.**) To effectively measure disturbances on the proposed BES.**
Industry Need (Provide a detailed statement justifying the need for the proposed standard, along with any supporting documentation**.)** **In order to support the NERC Event Analysis Program and to facilitate comprehensive review of disturbances on the BES, a robust Disturbance Monitoring standard is necessary. Review of the existing PRC-002-NPCC-01 is necessary to ensure the existing requirements are adequate to accommodate the FERC approved BES definition with its expanded applicability.**
Brief Description (Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.**)** **Review PRC-002-NPCC-01 as necessary with due consideration to the revised BES definition as filed with FERC and revise PRC-002-NPCC-01 accordingly to ensure that sufficient DM equipment is installed to measure and record disturbances on the BES. In addition all NPCC BOD approved interpretations as applicable to the standard will be incorporated into the revised standard. Consideration to all applicable NPCC Compliance Guidance Statements regarding applicability will be reflected in the revision as well as review and potential revision to the Implementation Plan.**

Reliability Functions

The Standard will Apply to the Following Functions (Check all applicable boxes.)		
☒	Reliability Coordinator	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
☐	Balancing Authority	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules.
☐	Planning Authority	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
☐	Transmission Service Provider	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.
☒	Transmission Owner	The entity that owns and maintains transmission facilities.
☐	Transmission Operator	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.
☐	Transmission Planner	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.
☐	Resource Planner	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.
☐	Generator Operator	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
☒	Generator Owner	Entity that owns and maintains generating units.
☐	Purchasing-Selling Entity	The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.
☐	Distribution Provider	Provides and operates the "wires" between the transmission system and the customer.
☐	Load-Serving Entity	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check all boxes that apply.)*	
☐	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.
☐	5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
Recognizing that reliability is an Common Attribute of a robust North American economy:
1. A reliability standard shall not give any market participant an unfair competitive advantage.Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft a standard based on this description.)

The standard is based on the current BES definition and will be reviewed and revised as necessary to reflect the new FERC approved BES definition.

Related Standards

Standard No.	Explanation

Related SARs or RSARs

SAR ID	Explanation

Information in a Regional Standard Authorization Request (RSAR)

The tables below identify information to be submitted in a Regional Standard Authorization Request to the NPCC Regional Standards Process Manager, NPCCstandard@npcc.org . The NPCC Regional Standards Process Manager shall be responsible for implementing and maintaining this form as needed to support the information requirements of the standards process.

Regional Standard Authorization Request Form

Title of Proposed Standard:	PRC-006-NPCC-2
Request Date:	03-31-2015

RSAR Requester Information

Name: Brian Robinson		**RSAR Type (Check box for one of these selections.)**	
Company:	NPCC	☐	New Standard
Telephone: 802-241-1400		☒	Revision to Existing Standard
Fax:	(866) 214-8632	☐	Withdrawal of Existing Standard
Email:	Brian.Robinson@utilitysvcs.com	☐	Urgent Action

Purpose (Describe the purpose of the proposed standard – what the standard will achieve in support of reliability.**)**

The purpose of the proposed RSAR is to review regional reliability standard PRC-006-NPCC-1 for potential revisions or retirements made necessary by the enactment of NERC's PRC-006-1 Automatic Underfrequency Load Shedding and PRC-024-1 Generator Frequency and Voltage Protective Relay Settings standards.

Attachment C in PRC-006-NPCC-1 is to be reviewed to address the implications of the design assessment, in accordance with Requirement R4 of PRC -006-1, not meeting the program performance characteristics as identified in Requirement R3 of PRC -006-1.

PRC-006-NPCC-1 is to be reviewed to determine if the applicability of the standard needs to be revised in accordance with Project 2014-01 Dispersed Generation Resources.

PRC-006-NPCC-1 is to be reviewed in order to determine if the performance requirements as contained in the criteria of NPCC Directory#12 Sections 5.1.1 and 5.1.2 should be explicitly included in the requirements of the Regional Standard.

PRC-006-NPCC-1 is to be reviewed in order to update Table 4 in Attachment C in accordance with the 2013 NPCC UFLS Adequacy Assessment. Additionally, the applicability of Requirements R4 and R5 will be reviewed to consider that Hydro Quebec is not part of the Eastern Interconnection.

Industry Need (Provide a detailed statement justifying the need for the proposed standard, along with any supporting documentation**.)**

To enhance efficiency and cost effectiveness, it must be determined if PRC-006-NPCC-1 requirements should be revised or retired considering the industry adoption of NERC standards PRC-006-1 and PRC-024-1, without sacrificing the ability to preserve the System during declining frequency and voltage excursion events.

Brief Description (Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.**)**

The requirements in PRC-006-NPCC-1 will be reviewed individually for revision or deletion with respect to NERC standards PRC-006-1 and PRC-024-1. Both PRC-006-NPCC-1and PRC-006-1 mandate effective automatic underfrequency load shedding, and PRC-024-1 ensures that generator protective relays are set such that the units remain connected during frequency and voltage excursions. However, there are certain similar requirements in each of these standards that should be reviewed to determine whether there is an opportunity to revise or delete the requirements of PRC-006-NPCC-1 to eliminate redundancy and the resulting double jeopardy.

PRC-006-1 requires in Requirement R4 that "Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years…". Revision to Attachment C of PRC-006-NPCC-1 needs to be considered to address the circumstance surrounding a design assessment that does not meet the performance characteristics as identified in Requirement R3

of PRC -006-1.

Additionally, as identified by SS38 there are aspects of the performance requirements in NERC PRC -006-1 that are slightly more relaxed than the criteria in Directory#12 and these more stringent attributes of the NPCC criteria were not incorporated into the regional standard.

Specifically, the NPCC criteria in Directory#12 (Sections 5.1.1 and 5.1.2) state that frequency should not remain below 59.5Hz for more than 30 seconds and should not remain below 58.5 Hz. for more than 10 seconds.

Incorporating these performance attributes from the criteria in Directory#12 into PRC -006-NPCC-1 will facilitate the retirement of Directory#12 when the regional standard is fully implemented within the region.

Revise Table 4 Attachment C to reflect the modified Quebec UFLS program parameters as recommended in the 2013 NPCC UFLS Adequacy Assessment and review the applicability of Requirements R4 and R5 as they pertain to the Quebec Interconnection.

The review will be governed by bullet 1 of the NERC Rules of Procedure, Section 312, Regional Reliability Standards, which reads "Regional Entities may propose Regional Reliability Standards that set more stringent reliability requirements than the NERC Reliability Standard or cover matters not covered by an existing NERC Reliability Standard."

Reliability Functions

The Standard will Apply to the Following Functions (Check all applicable boxes.)		
☐	Reliability Coordinator	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
☐	Balancing Authority	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules.
☒	Planning Coordinator	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
☐	Transmission Service Provider	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.
☒	Transmission Owner	The entity that owns and maintains transmission facilities.
☐	Transmission Operator	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.
☐	Transmission Planner	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.
☐	Resource Planner	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.
☐	Generator Operator	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
☒	Generator Owner	Entity that owns and maintains generating units.
☐	Purchasing-Selling Entity	The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.
☒	Distribution Provider	Provides and operates the "wires" between the transmission system and the customer.
☐	Load-Serving Entity	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check all boxes that apply.)*	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.
☒	5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
Recognizing that reliability is an Common Attribute of a robust North American economy:
1. A reliability standard shall not give any market participant an unfair competitive advantage.Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft a standard based on this description.)

Review and compare regional standard PRC-006-NPCC-1with continent-wide standards PRC-006-1 and PRC-024-1 to determine if revisions are necessary.

Determine the necessity for including wording to address dispersed generation resources.

Incorporate more stringent aspects of Directory#12 in order to facilitate future retirement of Directory#12.

Related Standards

Standard No.	Explanation
PRC-006-1	NERC Automatic Underfrequency Load shedding
PRC-024-1	NERC Generator Frequency and Voltage Protective Relay Settings

Related SARs or RSARs

SAR ID	Explanation

Information in a Regional Standard Authorization Request (RSAR)

The tables below identify information to be submitted in a Regional Standard Authorization Request to the NPCC Regional Standards Process Manager, NPCCstandard@npcc.org . The NPCC Regional Standards Process Manager shall be responsible for implementing and maintaining this form as needed to support the information requirements of the standards process.

Regional Standard Authorization Request Form

Title of Proposed Standard:	PRC-006-NPCC-2
Request Date:	03-31-2015

RSAR Requester Information

Name: Brian Robinson		**RSAR Type (Check box for one of these selections.)**	
Company:	NPCC	☐	New Standard
Telephone: 802-241-1400		☒	Revision to Existing Standard
Fax:	(866) 214-8632	☐	Withdrawal of Existing Standard
Email:	Brian.Robinson@utilitysvcs.com	☐	Urgent Action

Purpose (Describe the purpose of the proposed standard – what the standard will achieve in support of reliability.**)**

The purpose of the proposed RSAR is to review regional reliability standard PRC-006-NPCC-1 for potential revisions or retirements made necessary by the enactment of NERC's PRC-006-2~~1~~ Automatic Underfrequency Load Shedding and PRC-024-1 -Generator Frequency and Voltage Protective Relay Settings standards.

Attachment C in PRC-006-NPCC-1 is to be reviewed to address the implications of the design assessment, in accordance with Requirement R4 of PRC-~~-~~006-2~~1~~, not meeting the program performance characteristics as identified in Requirement R3 of PRC-~~-~~006-2~~1~~.

PRC-006-NPCC-1 is to be reviewed to determine if the applicability of the standard needs to be revised in accordance with Project 2014-01 Dispersed Generation Resources.

PRC-006-NPCC-1 is to be reviewed in order to determine if the performance requirements as contained in the criteria of NPCC Directory #12 Sections 5.1.1 and 5.1.2 should be explicitly included in the requirements of the Regional Standard.

PRC-006-NPCC-1 is to be reviewed in order to update Table 4 in Attachment C in accordance with the 2013 NPCC UFLS Adequacy Assessment. Additionally, the applicability of Requirements R4 and R5 will be reviewed to consider that Hydro Quebec is not part of the Eastern Interconnection.

Industry Need (Provide a detailed statement justifying the need for the proposed standard, along with any supporting documentation**.)**

To enhance efficiency and cost effectiveness, it must be determined if PRC-006-NPCC-1 requirements should be revised or retired considering the industry adoption of NERC standards PRC-006-2~~1~~ and PRC-024-1,- without sacrificing the ability to preserve the System during declining frequency and voltage excursion events.

Brief Description (Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.**)**

The requirements in PRC-006-NPCC-1 will be reviewed individually for revision or deletion with respect to NERC standards PRC-006-2~~1~~ and PRC-024-1. Both PRC-006-NPCC-1and PRC-006-2~~1~~ mandate effective automatic underfrequency load shedding, and PRC-024-1 ensures that generator protective relays are set such that the units remain connected during frequency and voltage excursions. However, there are certain -similar requirements in each of these standards that should be reviewed to determine whether there is an opportunity to revise or delete the requirements of PRC-006-NPCC-1 -to eliminate redundancy and the resulting double jeopardy.

PRC-006-2~~1~~ requires in Requirement R4 that "Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years…"~~.~~ Revision to Attachment C of PRC-006-NPCC-1 needs to be considered to address the circumstance surrounding a design assessment that does not meet the performance characteristics as identified in Requirement R3 of PRC-~~-~~006-2~~1~~.

Additionally, as identified by SS38 there are ~~aspects of the~~ performance requirements in NERC PRC-~~-~~006-2~~1~~ that are ~~slightly more relaxed~~less stringent than the criteria in Directory #12. ~~and~~ T~~t~~hese ~~se~~ more stringent ~~attributes of the~~ NPCC criteria were not incorporated into the regional standard.

Specifically, the NPCC criteria in Directory #12 (Sections 5.1.1 and 5.1.2) state that (1) frequency decline is arrested at no less than 58.0 Hz for the portions of NPCC in the Eastern Interconnection and 56.0 Hz for the portion of NPCC in the Québec Interconnection and (2) frequency should not remain below 59.5 Hz for more than 30 seconds and should not remain below 58.5 Hz. for more than 10 seconds.

Incorporating these performance attributes from the criteria in Directory #12 into PRC-~~-~~006-NPCC-1 will facilitate the retirement of Directory #12 when the regional standard is fully implemented within the region.

Revise Table 4 Attachment C to reflect the modified Quebec UFLS program parameters as recommended in the 2013 NPCC UFLS Adequacy Assessment and review the applicability of Requirements R4 and R5 as they pertain to the Quebec Interconnection.

The review will be governed by bullet 1 of the NERC Rules of Procedure, Section 312, Regional Reliability Standards, which reads "Regional Entities may propose Regional Reliability Standards that set more stringent reliability requirements than the NERC Reliability Standard or cover matters not covered by an existing NERC Reliability Standard."

The review will include an assessment of the need to include language regarding dispersed generating resources.

Reliability Functions

The Standard will Apply to the Following Functions (Check all applicable boxes.)		
☐	Reliability Coordinator	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any

		Transmission Operator's vision.
☐	Balancing Authority	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules.
☒	Planning Coordinator	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
☐	Transmission Service Provider	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.
☒	Transmission Owner	The entity that owns and maintains transmission facilities.
☐	Transmission Operator	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.
☐	Transmission Planner	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.
☐	Resource Planner	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.
☐	Generator Operator	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
☒	Generator Owner	Entity that owns and maintains generating units.
☐	Purchasing-Selling Entity	The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.
☒	Distribution Provider	Provides and operates the "wires" between the transmission system and the customer.
☐	Load-Serving Entity	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check all boxes that apply.)*

☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.
☒	5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.
Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*	
Recognizing that reliability is an Common Attribute of a robust North American economy:	
1. A reliability standard shall not give any market participant an unfair competitive advantage.Yes	
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes	
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes	
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes	

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft a standard based on this description.)

Review and compare regional standard PRC-006-NPCC-1with continent-wide standards PRC-006-21 -and PRC-024-1 to determine if revisions are necessary.

Determine the necessity for including wording to address dispersed generation resources.

Incorporate the more stringent aspects of Directory #12 in order to facilitate future retirement of Directory #12.

Related Standards

Standard No.	Explanation
PRC-006-21	NERC Automatic Underfrequency Load shedding
PRC-024-1	NERC Generator Frequency and Voltage Protective Relay Settings

Related SARs or RSARs

SAR ID	Explanation

20150304-3070 FERC PDF (Unofficial) 03/04/2015

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD15-2-000

March 4, 2015

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005

Attention: Milena Yordanova
Associate Counsel for North American Electric Reliability Corporation

Reference: Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard PRC-006-2

Dear Ms. Yordanova:

On December 15, 2014, the North American Electric Reliability Corporation (NERC) filed a petition seeking approval of the proposed Reliability Standard PRC-006-2 (Automatic Underfrequency Load Shedding), the associated implementation plan, the violation risk factors, and violation security levels and the retirement of currently effective Reliability Standard PRC-006-1.

The purpose of proposed Reliability Standard PRC-006-2 is to establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures. Proposed Reliability Standard PRC-006-2 states that it is applicable to planning coordinators, UFLS entities (a term defined in the proposed Reliability Standard), and transmission owners that own elements identified in the underfrequency load shedding programs established by planning coordinators. The petition maintains that the proposed Reliability Standard contains changes that address the Commission's concern in Order

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No. 763 relating to Requirement R9 of PRC-006-1.[1] In Order No. 763, the Commission approved Reliability Standard PRC-006-1. In addition, the Commission directed NERC to include explicit language in a subsequent version of the Reliability Standard clarifying that applicable entities are required to implement corrective actions identified by the planning coordinator in accordance with a schedule established by the same planning coordinator.[2] The petition states that this is accomplished by additional language in Reliability Standard PRC-006-2, Requirements R9 and R10, and the introduction of a new Requirement R15. The revisions also place deadlines for corrective action plans to be developed by the planning coordinator. The petition states that these proposed deadlines are within the timeframes identified in Requirements R4, R5 or R12.

NERC's filing was noticed on December 17, 2014, with interventions, comments and protests due on or before January 16, 2015. Dominion Resources Services, Inc. filed a timely motion to intervene raising no issues.

NERC's uncontested filing is hereby approved pursuant to the relevant authority delegated to the Director, Office of Electric Reliability under 18 C.F.R. § 375.303 (2014), effective as of the date of this Order.

This action shall not be construed as approving any other application, including proposed revisions of Electric Reliability Organization or Regional Entity rules or procedures pursuant to 18 C.F.R. § 375.303(a)(2)(i). Such action shall not be deemed as recognition of any claimed right or obligation associated therewith and such action is without prejudice to any findings or orders that have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Electric Reliability Organization or any Regional Entity.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713 (2014).

Sincerely,

Michael Bardee, Director
Office of Electric Reliability

[1] *Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards*, Order No. 763, 139 FERC ¶ 61,098, *order granting clarification*, 140 FERC ¶ 61,164 (2012).

[2] Order No. 763, 139 FERC ¶ 61,098 at P 48.

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Document Content(s)

RD15-2-000.DOCX.....1-2

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2008-02: Underfrequency Load Shedding (UFLS)

Requested Approval

- PRC-006-2: Automatic Underfrequency Load Shedding

Requested Retirement

- PRC-006-1: Automatic Underfrequency Load Shedding

Prerequisite Approvals

- None

Revisions to Defined Terms in the NERC Glossary

- None

Applicable Entities

- Planning Coordinators
- UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:
    - Transmission Owners
    - Distribution Providers
- Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators

Effective Date

This standard is effective on the first day of the first calendar quarter six months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing PRC-006-1

PRC-006-1 shall be retired at midnight of the day immediately prior to the Effective Date of PRC-006-2.

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

Directory#1 Design and Operation of the BPS

Response to Comments Received in 2nd Open Process
May 22nd, 2014 to July 07, 2014

(As drafted by the CO7/CP11Working Group)

Comment from – NPCC:

~~*Comment : 28*~~

NPCC respectively submits comments on the draft of Directory 1 which was posted on May 22nd, 2014 for review and comment.

CO7/CP11 has recommended removing the list of ERO Standards associated with Directory#1 since regulatory approval processes can lead to different versions of the same ERO Standard in effect and concern that such a list does not belong in a document applicable to only the BPS. CO7/CP11 has also recommended removing these lists from all other NPCC Directories.

However, the NPCC Directory Development and Revision Manual states that each Directory identifies the list of NERC ERO Reliability Standards that are associated with a specific Directory in order to insure that the criteria is not inconsistent with the ERO Standards as required by the NERC Rules of Procedure.

NPCC Directories in addition to consolidating related information for NPCC Criteria, Guidelines and Procedures also serve as the mechanism for insuring that the regional criteria remain consistent with the ERO Standards.

As the NERC ERO Standards are revised and evolve NPCC Staff is required to review the standard requirements in order to insure that the criteria remains more stringent or specific than the associated NERC Standards and the list of ERO Standards contained in each Directory is an important tool in this effort.

Therefore, NPCC is recommending that these lists of ERO standards should remain in Directory#1 as well as all other Directories, unless an equally efficient alternative is proposed to compare the associated ERO standard requirements with the criteria contained within NPCC Directories.

CO7/CP11 Response:
9/17/2014

Thank you for the comment.
Comment not accepted.

CO7/CP11 Members restated their concern that since the Directory contains criteria applicable only to the 'BPS' a list of 'BES' ERO standards should not be included in the document

NPCC noted that the Regional Standards Committee (RSC) was responsible for the overall Directory project and that if a decision is made to remove the list of ERO standards it should be made by the RSC and applied globally to all NPCC Directories.

CO7/CP11 Members agreed to identify this issue with their RSC representatives and Mr. Dunbar took an action item to have the issue placed on the RSC meeting of December 4th and 5th in Halifax.

NPCC, Inc.

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

April 6th, 2015

Decision

Should a list of related ERO Standards be included in each NPCC Directory?

Pros

1. Facilitates identification of standards functionally related to the criteria within a specific Directory.
2. As ERO standards are revised the list of standards identifies sections of the criteria that should be reviewed for duplicity or lack of stringency.
3. NERC Rules of Procedures mandate criteria that is not inconsistent with the standards and such a list insures that the Directories are maintained consistent with the ROP.

Cons

1. NPCC criteria are applicable to only the NPCC BPS and a list of ERO standards applicable to the BES should not be included in a Directory.
2. Creates Compliance ambiguity.

REGIONAL STANDARDS COMMITTEE

Chairman:

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Alternate

Sector (2) - Reliability Coordinators

New York Independent System Operator

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ISO New England, Inc.

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Independent Electricity System Operator

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Sector (3) - Transmission Dependent Utilities ("TDUs"); Distribution Companies and Load-Serving Entities ("LSEs")

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Communications Reliability Standards	**)**	**Docket No. RM14-13-000**
	)	

SUPPLEMENTAL COMMENTS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IN RESPONSE TO NOTICE OF PROPOSED RULEMAKING

The North American Electric Reliability Corporation ("NERC") hereby submits these supplemental comments in response to the Notice of Proposed Rulemaking ("NOPR")[1] issued by the Federal Energy Regulatory Commission ("FERC" or "Commission") in this proceeding on September 18, 2014. In the NOPR, the Commission proposes to approve proposed Reliability Standards COM-001-2 (Communications) and COM-002-4 (Operating Personnel Communications Protocols), the Violation Risk Factors, Violation Severity Levels, and the proposed Implementation Plans for both proposed Reliability Standards. In addition, the Commission proposes to approve three new terms to be added to the NERC Glossary of Terms ("Interpersonal Communication," "Alternative Interpersonal Communication," and "Operating Instruction").

These supplemental comments update the Commission following recent actions by the NERC Board of Trustees ("NERC Board") adopting revisions to certain proposed TOP and IRO Reliability Standards referenced in NERC's December 1, 2014 Comments ("Comments") submitted in this proceeding.

[1] *Communications Reliability Standards*, Notice of Proposed Rulemaking, 148 FERC ¶ 61,210 (2014).

I. Procedural History

On May 14, 2014, NERC submitted a petition for approval of proposed Reliability Standards COM-001-2 and COM-002-4. Proposed COM-001-2 establishes a clear set of requirements for what communication capabilities various functional entities must maintain for reliable communications. Proposed COM-002-4 requires entities to have or create a set of documented communications protocols that include certain minimum mandatory protocols.

On September 18, 2014, the Commission issued its NOPR. Specifically related to these supplemental comments, the Commission's NOPR sought clarification regarding the scope and meaning of the proposed definitions of "Interpersonal Communication" and "Alternative Interpersonal Communication." The Commission explained that the definitions do not provide a minimum expectation of communication performance, and noted that it is unclear whether the definition of "Interpersonal Communication" includes mediums used directly to exchange or transfer data.

NERC's Comments clarified that the standard drafting team did not include mediums used to exchange data within proposed COM-001-2. The standard drafting team answered comments during the standard development process on the same question and responded that data exchange is addressed by the currently enforceable Reliability Standards IRO-010-1a and IRO-014-1. NERC's Comments included discussion of the coverage within these two Reliability Standards. The standard drafting team determined that the Requirements in these two IRO Reliability Standards provided the necessary mandatory Requirements to ensure proper data exchange.

NERC also explained in its Comments that Project 2014-03: Revisions to TOP and IRO Standards included coverage of mediums and data in its proposed changes to certain TOP and

IRO Reliability Standards. Data exchange capabilities are directly addressed in proposed TOP-001-3, as well as in proposed IRO-002-4, Requirement R1. The data itself is covered in proposed IRO-010-2 and proposed TOP-003-3. NERC noted that, at the time of the submission of NERC's Comments, these proposed Reliability Standards were Board-adopted with the exception of TOP-001-3. On November 13, 2014, the NERC Board adopted proposed Reliability Standard TOP-001-3.

II. Supplemental Comments

NERC will submit the proposed TOP and IRO Reliability Standards for approval in a separate petition, but provides additional information in this proceeding because the Commission raised a concern in the NOPR regarding the coverage of mediums used directly to exchange or transfer data in proposed COM-001-2.[2] At the time NERC submitted its Comments, the proposed TOP and IRO Reliability Standards were still in formal development. Four of the proposed Reliability Standards include specific coverage related to data exchange. Collectively, these proposed Requirements complement COM-001-2 by requiring data exchange capabilities for Reliability Coordinators, Transmission Operators, Balancing Authorities, Generator Operators, and Distribution Providers.

A. TOP-001-3

The purpose of TOP-001-3 is to prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences. Proposed TOP-001-3 includes two Requirements specifically related to data exchange and specifically call for having a capability to exchange data. Proposed Requirement R19 provides that "[e]ach Transmission Operator shall have data

[2] NERC will also include this information in the future petition for approval of the below proposed Reliability Standards.

exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Transmission Operator Area." Requirement R20 provides that "[e]ach Balancing Authority shall have data exchange capabilities with the entities that it has identified that it needs data from in order to maintain reliability in its Balancing Authority Area."

B. IRO-010-2

The purpose of proposed Reliability Standard IRO-010-2 is to prevent instability, uncontrolled separation, or Cascading outages that adversely impact reliability, by ensuring that the Reliability Coordinator has the data it needs to monitor and assess the operation of its Reliability Coordinator Area. Requirements R1 and R2 of proposed Reliability Standard IRO-010-2 address the maintenance and distribution of the data specification, and Requirement R1 describes specific data to be included within the data specification. Requirement R1 provides that "[t]he Reliability Coordinator shall maintain a documented specification for the data necessary to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments." Requirement R2 provides that "[t]he Reliability Coordinator shall distribute its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments." Requirement R3 addresses concerns about data exchange through secured networks by requiring that each entity satisfy the obligations of the documented specifications by using a mutually agreeable format, mutually agreeable process for resolving data conflicts, and mutually agreeable security protocol.

C. TOP-003-3

The purpose of proposed Reliability Standard TOP-003-3 is to ensure that Transmission Operators and Balancing Authorities have the data needed to fulfill their operational and planning responsibilities. The proposed standard consists of five Requirements, including

requirements for Balancing Authorities and Transmission Operators to maintain, and distribute to relevant entities, data specifications for the data necessary to perform various analyses and assessments. The proposed standard also requires entities receiving data specifications to respond according to mutually-agreed parameters.

Proposed Requirement R1 requires each Transmission Operator to maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: (i) a list of data and information needed to support these analyses, monitoring, and assessments; (ii) provisions for the notification of current Protection System and Special Protection System status or degradation that impacts System reliability; (iii) a periodicity for providing data; and (iv) the deadline by which the respondent (i.e. recipient) is to provide the indicated data. Similarly, proposed Requirement R2 requires each Balancing Authority to maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. Proposed Requirements R3 and R4 require each Transmission Operator (R3) and Balancing Authority (R4) to distribute its data specification to the entities that have the necessary data.

Proposed Requirement R5 provides that each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented data specification using: (i) a mutually agreeable format; (ii) a mutually agreeable process for resolving data conflicts; and (iii) a mutually agreeable security protocol.

D. IRO-002-4

The purpose of proposed Reliability Standard IRO-002-4 is to provide System Operators with the capabilities necessary to monitor and analyze data needed to perform their reliability functions. Proposed Requirement R1 requires each Reliability Coordinator to have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities as it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. This would include maintaining data exchange capabilities with another Reliability Coordinator or another functional entity not specifically listed, if "deemed necessary" by the Reliability Coordinator to obtain necessary data.

Requirements R3[3] and R4[4] include monitoring requirements for each Reliability Coordinator within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas. Requirement R4 also mandates that each Reliability Coordinator "shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel…over a redundant infrastructure."

III. Conclusion

For the reasons set forth above, NERC respectfully requests that the Commission accept these supplemental comments for consideration.

[3] Requirement R3 provides that "[e]ach Reliability Coordinator shall monitor Facilities, the Status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances with its Reliability Coordinating area."

[4] Requirement R4 provides that "[e]ach Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure."

Respectfully submitted,

/s/ William H. Edwards

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Date: March 6, 2015

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding. Dated at Washington, D.C. this 6th day of March, 2015.

/s/ William H. Edwards
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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RD15-3-000**

SUPPLEMENTAL PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARDS PRC-001-1.1(ii), PRC-019-2, AND PRC-024-2

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Exhibit A Proposed Reliability Standards
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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RD15-3-000**

SUPPLEMENTAL PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARDS PRC-001-1.1(ii), PRC-019-2, AND PRC-024-2

Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5[2] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, the North American Electric Reliability Corporation ("NERC")[3] hereby submits for Commission approval the following proposed Reliability Standards (Exhibit A), which have been modified to adjust the applicability of the proposed Reliability Standards to dispersed generation resources:[4]

- PRC-001-1.1(ii) (System Protection Coordination);[5]
- PRC-019-2 (Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection); and
- PRC-024-2 (Generator Frequency and Voltage Protective Relay Settings).

NERC requests that the Commission approve the proposed Reliability Standards and find that each is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[6]

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[1] 16 U.S.C. § 824o (2012).

[2] 18 C.F.R. § 39.5 (2014).

[3] The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *N. Amer. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006).

[4] Dispersed generation resources as used in this petition refers to variable generation that depends on a primary fuel source which varies over time and cannot be stored. *See* Ex. C to the related February 6 Petition.

[5] An explanation of the NERC numbering convention for Reliability Standards is available on the NERC web site at: http://www.nerc.com/pa/Stand/Resources/Documents/NERC_standards_numbering_system_V2.pdf.

[6] Unless otherwise designated, capitalized terms shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary of Terms"), *available at* http://www.nerc.com/files/Glossary_of_Terms.pdf.

On February 6, 2015, NERC filed a petition ("February 6 Petition")[7] for the approval of five proposed Reliability Standards, which were modified to adjust their applicability to dispersed generation resources. Similarly, in this Supplemental Petition, NERC proposes changes to PRC-001, PRC-019, and PRC-024 to clarify their applicability to dispersed generation resources.

NERC requests that the Commissions consider the proposed standards in this Supplemental Petition as part of the proceeding for approval of the February 6 Petition. NERC also requests approval of the Implementation Plan for each proposed Reliability Standard (Exhibit B).

The proposed changes do not affect the Violation Risk Factors ("VRFs"), Violation Severity Levels ("VSLs"), or the Measures associated with the proposed Reliability Standards subject to this Supplemental Petition.

As required by Section 39.5(a)[8] of the Commission's regulations, this Supplemental Petition presents the technical basis and purpose of the proposed Reliability Standards, a summary of the development history (Exhibit D), and a demonstration that the proposed Reliability Standards meet the criteria identified by the Commission in Order No. 672[9] (Exhibit C). This Supplemental Petition incorporates by reference Exhibit C (Draft Technical White Paper), Exhibit E (Summary of Development History and Complete Record of Development of Proposed Reliability Standards), and Exhibit F (Standard Drafting Team Roster for NERC

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[7] *See NERC Petition for approval of PRC-004-2.1(i)a; PRC-004-4; PRC-005-2(i); PRC-005-3(i) and VAR-002-4*, Docket: RD15-3-000.

[8] 18 C.F.R. § 39.5(a) (2012).

[9] The Commission specified in Order No. 672 certain general factors it would consider when assessing whether a particular Reliability Standard is just and reasonable. *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 262, 321-37, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

Standards Development Project 2014-01) of the February 6 Petition. Section C (Definition of Bulk Electric System) and Section F (Design and Operational Characteristics of Dispersed Power Producing Resources) of the February 6 Petition are also incorporated by reference.[10]

I. EXECUTIVE SUMMARY

The proposed revisions clarify how the unique operating characteristics of dispersed power producing resources impact the applicability of NERC Reliability Standards. As NERC has previously asserted, in order to ensure that Reliability Standards are applied in a cost-effective manner and that the applicability of Reliability Standards is focused on entities having a material impact on reliability of the Bulk-Power System, it is necessary to provide greater specificity in the applicability section of the Reliability Standards.[11] The Commission acknowledged the need for such clarity and prioritization in Order No. 693,[12] and has, in the past, approved Reliability Standards with applicability based on electric facility characteristics.[13]

Dispersed power producing resources, such as wind and solar, are generally considered to be variable energy resources. As explained below and in the February 6 Petition, the design and operating characteristics of these resources are different than traditional generation and Reliability Standards should account for these differences.

The proposed Reliability Standards reflect in-depth technical analysis by the NERC Dispersed Generation Resources Standard Drafting Team, which considered the technical characteristics of dispersed generation and the risk to the Bulk-Power System associated with

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[10] If the Commission decides to separately docket this Supplemental Petition, NERC requests that a copy of the February 6 Petition be included with this Supplemental Petition in the new docket to ensure a complete record for consideration.

[11] *See Mandatory Reliability Standards for the Bulk-Power System*, Notice of Proposed Rulemaking, 117 FERC ¶ 61,084 (2006) at P 49.

[12] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 98, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[13] *See also*, EOP-010-1, FAC-003-3, PRC-005-2, and PRC-022-1.

this type of generation facilities. The standard drafting team reviewed several groups of Reliability Standards applicable to dispersed generation prior to recommending the proposed changes to the three Reliability Standards listed above.

The standard drafting team determined that when evaluated individually, the components of dispersed power generation, such as individual wind or solar units, often do not pose a significant risk to the reliability of the Bulk-Power System. However, reliability could be improved by ensuring the equipment utilized to aggregate these individual units to a common point of interconnection with the Bulk-Power System is operated and maintained as required by the NERC Reliability Standards. As a result, NERC is proposing the changes to the three Reliability Standards included in this Supplemental Petition in addition to those submitted in the February 6 Petition.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[14]

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III. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[15] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Bulk-Power System, and with the duties of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[16] of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)[17] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard.

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[14] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2012), to allow the inclusion of more than two persons on the service list in this proceeding.

[15] 16 U.S.C. § 824o (2012).

[16] *Id.* § 824(b)(1).

[17] *Id.* § 824o(d)(5).

Section 39.5(a)[18] of the Commission's regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.

The Commission is vested with the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[19] and Section 39.5(c)[20] of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standards were developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[21] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[22]

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[18] 18 C.F.R. § 39.5(a) (2014).

[19] 16 U.S.C. § 824o(d)(2).

[20] 18 C.F.R. § 39.5(c)(1).

[21] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672 at P 334, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006) ("Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.").

[22] The NERC Rules of Procedure are available at http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx. The NERC Standard Processes Manual is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

In its order certifying NERC as the Commission's ERO, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards and thus satisfies the criteria for approving Reliability Standards.[23] The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk-Power System. NERC considers the comments of all stakeholders, and a vote of stakeholders and the NERC Board of Trustees is required to approve a Reliability Standard before the Reliability Standard is submitted to the Commission for approval.

C. History of Project 2014-01

Project 2014-01, Standards Applicability for Dispersed Generation Resources, was initiated in response to industry request and designed to ensure that the Generator Owners and Generator Operators of dispersed generation resources are appropriately assigned responsibility for performance in NERC Reliability Standard requirements that impact the reliability of the Bulk-Power System, given the unique operating characteristics of these resources.

The goal of Project 2014-01 was to review and revise the applicability of all of the Generator Owner- and Generator Operator-related Reliability Standards and ensure that only those dispersed generation resources that could affect the reliability of the Bulk-Power System are subject to applicable Reliability Standards. The standard drafting team identified PRC-005, FAC-008, PRC-023, PRC-025, PRC-004, and VAR-002 for further in-depth review. In addition, the standard drafting team considered the group of IRO, MOD, PRC and TOP Reliability Standards, which require outage and protection, control coordination, planning and data reporting, among other reliability concerns.[24]

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[23] Order No. 672 at PP 268, 270.

[24] For a list of all Reliability Standards considered, *see* App. A to Ex. C to the February 6 Petition.

The standard drafting team established prioritization criteria for the review and modification of applicability changes recommended to the NERC Reliability Standards listed above. The team evaluated each requirement to identify the appropriate applicability that best supports the reliable operation of the Bulk-Power System. After the standard drafting team identified a standard or requirement where changes to the applicability were warranted, it performed a prioritization. Any standard or requirement which required modifications were assigned a high, medium, or low priority.[25] Following a technical review, the standard drafting team identified five high-priority standards and drafted revisions to these standards. The proposed revisions were included in the February 6 Petition and are pending Commission approval.

The standard drafting team also identified medium-priority Reliability Standards, which included PRC-001-1.1, PRC-019 and PRC-024. The standards drafting team prepared revisions to these three Reliability Standards. The standards drafting team did not make any technical content changes beyond the changes necessary to revise the applicability of the three medium-priority Reliability Standards. The proposed changes are designed to ensure consistent application of the NERC Reliability Standards to dispersed power producing resources.

In addition, the standards drafting team identified four regional Reliability Standards as low priority. A list of the Reliability Standards considered and their prioritization order is included in Appendix B to Exhibit C to the February 6 Petition. Further proposed Reliability

[25] The standards and requirements priorities were established as follows: 1) high priority was assigned if compliance-related efforts with no appreciable reliability benefit would require not only significant resources but also would require efforts to be initiated by an entity well in advance of the implementation date; 2) medium priority was assigned if significant effort and resources with no appreciable reliability benefit would be required by an entity to be compliant; and 3) low priority was assigned to other changes that may need to be made to further ensure requirements add to reliability, but are not perceived as a significant compliance burden. Reliability Standards PRC-004-2.1a, PRC-005-1.1b, PRC-005-2, VAR-002-2b and VAR-002-2b were identified as "high priority." *See* App. B to Ex. C to the February 6 Petition.

Standards from this Project will be the subject of a future separate petition if the NERC Board adopts additional proposed Reliability Standards.

A detailed description of the standard drafting team considerations for each reviewed Reliability Standard is included in the Draft Technical White Paper ("Technical White Paper") **(**Exhibit C to the February 6 Petition**)**.

D. History of the Proposed Reliability Standards

1. PRC-001-1.1(ii)

Reliability Standard PRC-001-1 was approved by the Commission in Order No. 693.[26] On February 3, 2015, NERC filed a petition for the approval of PRC-001-1.1(i), which will replace PRC-001-1.1. The petition is pending Commission approval.[27]

2. PRC-019-2 and PRC-024-2

Reliability Standards PRC-019-1 and PRC-024-1 were approved by the Commission in Order No. 796 on March 20, 2014 as new Reliability Standards.[28]

IV. JUSTIFICATION FOR APPROVAL

As discussed in Exhibit C and below, the standard drafting team determined the proposed changes to the Reliability Standards satisfy the Commission's criteria in Order No. 672, and are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Provided below is the following: 1) a description of each proposed Reliability Standard and its reliability

[26] Order No. 693 at P 1467. An errata change was approved by the Standards Committee on April 11, 2012 to capitalize "Protection System" in accordance with the implementation plan for Project 2007-17, which developed a revised definition of "Protection System." The Commission approved the revised definition of "Protection System" and the associated implementation plan on February 3, 2012. *See N. Am. Elec. Reliability Corp*., 138 FERC ¶ 61,095 (2012).

[27] *See NERC Petition for Approval of Revisions to the Definition of "Remedial Action Scheme" and Proposed Reliability Standards,* Docket: RM15-13-000.

[28] *Generator Verification Reliability Standards,* Order No. 796, 146 FERC ¶ 61,213 at P 63 (2014).

purpose; and 2) justification for each of the proposed Reliability Standards on a requirement-by-requirement basis.

A. Proposed Reliability Standards

1. Purpose of PRC-001-1.1(ii)

Reliability Standard PRC-001-1.1 is designed to ensure that system protection is coordinated among operating entities. Reliability Standard PRC-001-1.1(i), which is currently pending regulatory approval, modified PRC-001-1 to incorporate the proposed definition of "Remedial Action Scheme" and eliminate the use of the term "Special Protection System." The proposed PRC-001-1.1(ii) reflects changes made to the currently-effective PRC-001-1.1.[29]

2. Purpose of PRC-019-2

Reliability Standard PRC-019-1 is designed to verify coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings. The revisions included in the proposed PRC-019-2 are necessary to align the applicability section of this Reliability Standard with the treatment of dispersed power producing resources within the revised definition of the Bulk Electric System.

3. Purpose of PRC-024-2

Reliability Standard PRC-024-1 is designed to ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions. The revisions included in the proposed PRC-024-2 are necessary to align the applicability section of this Reliability Standard with the treatment of dispersed power producing resources within the revised definition of the Bulk Electric System.

[29] If the Commission approves PRC-001-1(ii) prior to approval of PRC-001-1(i), NERC will reorder the numbering to appropriately reflect the timing.

4. Justification for Proposed Revisions

a) PRC-001-1.1(ii)

Based on the findings of the Technical White Paper, the standard drafting team made one revision of PRC-001-1.1. Requirement R3, Part 3.1 was modified to clarify that it is not applicable to individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.[30] The applicable language of the proposed PRC-001-1.1(ii) reads as follows:

> **R3.** A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.
>
> > **R3.1.** Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.
> >
> > • Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

As explained in the Technical White Paper,[31] Requirement R3 requires Generator Operators to coordinate new protective systems and changes to existing protective systems with their Transmission Operators. Under the existing industry practice, Generator Operators share and coordinate the protective relay settings at the point of interconnection (e.g. generator leads, radial generator tie-line, etc.) and potentially the main step-up transformer, but not the protective setting on operating (collection) buses, collection feeder, or individual generator protection schemes, as these protection systems do not directly coordinate with an interconnected utility's own protection systems. Relay protection functions such as underfrequency and overfrequency

[30] For a full discussion of Inclusion I4 of the revised Bulk Electric System and its effect on dispersed power resources, see Section C of the February 6 Petition.

[31] *Technical White Paper* at 16-17.

and undervoltage and overvoltage changes are independent of the interconnected utility's protective relay settings.[32]

In response to the findings of the Technical White Paper, the standard drafting team determined that coordination of new or changes to protective systems associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition are typically performed on the interconnecting facilities. New protective systems or changes to protective systems associated with these facilities should be coordinated with the Transmission Operators to ensure close coordination with the transmission protective systems. This type of coordination guarantees the overall protection systems operates as designed.

In some situations, the protective systems implemented on the individual generating units of dispersed power producing resources (i.e. individual wind turbines or solar panels/inverters) may need to be coordinated with other protective systems within the same dispersed power producing facility. However, the standards drafting team concluded that new protective systems or changes to these protective systems do not need to be coordinated with the transmission protective systems, as this coordination would not enhance the reliability of the Bulk-Power System.

Based on these findings, Requirement R3 was modified to reflect that coordination by a Generator Operator with its Transmission Operator of new or changes to existing protection systems on individual generating units of dispersed power producing resources is not required. The proposed revision is consistent with the Commission-approved revised Bulk Electric System definition.

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[32] *Id*.

b) PRC-019-2

Based on the findings of the Technical White Paper, the standard drafting team made one revision of Requirement R4, Part 4.2 of PRC-019-1. Subrequirement 4.2.3.1 was added to Requirement 4.2 to clarify that the Facilities listed in Requirement 4.2 include the aggregate dispersed generating facilities and not the individual units. The proposed revision is intended to provide for consistent application of the Requirement to generator Facilities included in the Bulk Electric System definition through Inclusion I4. The language of the proposed Part 4.2.3.1 reads as follows:

> **4.2.3** Generating plant/ Facility consisting of one or more units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating).
>
> > **4.2.3.1** This includes individual generating units of the dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition where voltage regulating control for the facility is performed solely at the individual generating unit of the dispersed power producing resources.

As explained in the Technical White Paper,[33] dispersed power producing resources typically utilize a site level voltage control scheme that directs the individual generating units to adjust their output to meet the voltage requirements at an aggregate Facility level. In these cases the individual generating units no longer respond once they reach their maximum capability in providing voltage or reactive changes. However, the individual generating units also need to be properly coordinated with protection trip settings on the aggregating equipment to mitigate risk of tripping under this scenario. Therefore, facilities that solely regulate voltage at the individual

[33] *Id*. at 21.

unit need to consider the Protection Systems at these individual units and their compatibility with the reactive and voltage limitations of the units.

Based on these findings, the standard drafting team determined that for those dispersed power producing facilities that only perform voltage regulating control at the individual generating unit level, coordination should take place at the individual generating unit level of the dispersed power producing resource. These facilities need to consider the Protection Systems at the individual units and their compatibility with the reactive and voltage limitations of the units. Where voltage regulating control is done at an aggregate level, applicability is already included under PRC-019 Requirement R4, Part 4.2.3. This revision is consistent with the Commission-approved revised Bulk Electric System definition.

c) PRC-024-2

Based on the findings of the Technical White Paper, the standard drafting team made two revisions to PRC-024-2. The standard drafting team determined that protective relay settings applied on both the individual generating units and on the aggregating equipment should be included in the language of the Reliability Standard. To reflect this change, the standards drafting team included footnote 4 to PRC-024-2 Requirement R1, and footnote 6 to Requirement R2. The applicable language of the proposed PRC-024-2 reads as follows:[34]

> **R1.** Each Generator Owner that has generator frequency protective relaying3 activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the "no trip zone" of PRC-024 Attachment 1, subject to the following exceptions:[4] *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
>
> > **Footnote 4:** For frequency protective relays associated with dispersed power producing resources identified

[34] Footnotes 3 and 5 remain unchanged and are omitted. For the full language of the proposed Reliability Standard, please see Exhibit A.

> through Inclusion I4 of the Bulk Electric System definition, this requirement applies to frequency protective relays applied on the individual generating unit of the dispersed power producing resources, as well as frequency protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.
>
> **R2.** Each Generator Owner that has generator voltage protective relaying activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2.[6] If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner's study. Requirement R2 is subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
>
> > **Footnote 6:** For voltage protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to voltage protective relays applied on the individual generating unit of the dispersed power producing resources, as well as voltage protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.

As explained in the Technical White Paper,[35] if the individual generating units at a dispersed power producing resource were excluded from this Reliability Standard, it is possible that large portions or perhaps the entire output of a dispersed power producing resource site could be lost during certain system disturbances. To address this reliability concern, the standard drafting team determined that Protection System settings should be applied on both the

[35] *Technical White Paper* at 22.

individual generating units and on the aggregate equipment, including on any Protection Systems applied on non-Bulk Electric System portions of the aggregating equipment.

The Technical White Paper further explains that for the purpose of compliance evidence, an entity should provide evidence for a single sample generating unit within a dispersed generation site. Registered entities would not be required to provide documentation for each individual unit if a single methodology was applied to set the Protection Systems for all units comprising the facility. The evidence related to a single sample generating unit would be in addition to the evidence required for any Protection System settings for the aggregating equipment.

Based on these technical findings, the standard drafting team made changes to the standard requirements to ensure these requirements are applied to the individual power producing resource up to the point of interconnection with the Bulk-Power System. The proposed changes to PRC-024-2 are consistent with the Commission-approved revised Bulk Electric System definition.

V. ENFORCEABILITY OF PROPOSED RELIABILITY STANDARDS

The proposed Reliability Standards include VRFs and VSLs. Because the Requirements contained in proposed Reliability Standards track with those contained in the already approved or proposed versions of the Reliability Standards, the standard drafting team determined that no revisions were necessary to the VSLs and VRFs for the proposed Reliability Standards.

The VSLs provide guidance on the way that NERC will enforce the Requirements of the proposed Reliability Standards. The VRFs are one of several elements used to determine an appropriate sanction when the associated Requirement is violated. The VRFs assess the impact to reliability of violating a specific Requirement. The VRFs and VSLs for the proposed

Reliability Standards comport with NERC and Commission guidelines related to their assignment. For a detailed review of the VRFs, the VSLs, and analysis of how the VRFs and VSLs were determined using these guidelines, please see Exhibit D.

The proposed Reliability Standards also include Measures that support each Requirement by clearly identifying what is required and how the Requirement will be enforced. These Measures help ensure that the Requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.[36] The Measures for the proposed Reliability Standards also remain unchanged from previous versions.

VI. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission:

- approve the proposed Reliability Standards included in Exhibit A; and
- approve the implementation plans included in Exhibit B.

[36] Order No. 672 at P 327 ("There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.").

Respectfully submitted,

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Counsel for the North American Electric Reliability Corporation

March 13, 2015

Exhibit A

Proposed Reliability Standards

A. Introduction

1. **Title:** **System Protection Coordination**

2. **Number:** PRC-001-1.1(ii)

3. **Purpose:**

   To ensure system protection is coordinated among operating entities.

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Transmission Operators

   4.3. Generator Operators

5. **Effective Date:**

   See the Implementation Plan for PRC-001-1.1(ii).

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:

R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.

R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.

- Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.

R4. Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:

R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.

R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.

R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

C. Measures

M1. Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Special Protection Systems in its area. (Requirement 6 Part 1)

M3. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Special Protection Systems. (Requirement 6 Part 2)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures 2 and 3.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Generator Operators:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

3. Levels of Non-Compliance for Transmission Operators:

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

3.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Failed to provide evidence of coordination when installing new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities as specified in R3.2.

3.4.2 Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

4. Levels of Non-Compliance for Balancing Authorities:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	August 25, 2005	Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0	Errata
1	November 1, 2006	Adopted by the NERC Board of Trustees	Revised
1.1	April 11, 2012	Errata adopted by the Standards Committee; (Capitalized “Protection System” in accordance with Implementation Plan for Project 2007-17 approval of revised definition of “Protection System”)	Errata associated with Project 2007-17
1.1	September 9, 2013	Informational filing submitted to reflect the revised definition of Protection	

		System in accordance with the Implementation Plan for the revised term.	
1.1(i)	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
1.1(ii)	February 12, 2015	Adopted by the NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources
2	May 9, 2012	Adopted by Board of Trustees	Deleted Requirements R2, R5, and R6.

Guidelines and Technical Basis

Rationale:
During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for the Applicability Exclusion in Requirement R3.1

Coordination of new or changes to protective systems associated with dispersed power producing resources identified through Inclusion I4 of the BES definition are typically performed on the interconnecting facilities. New or changes to protective systems associated with these facilities should be coordinated with the TOP as these protective systems typically must be closely coordinated with the transmission protective systems to ensure the overall protection systems operates as designed. While the protective systems implemented on the individual generating units of dispersed power producing resources at these dispersed power producing facilities (i.e. individual wind turbines or solar panels/inverters) may in some cases need to be coordinated with other protective systems within the same dispersed power producing facility, new or changes to these protective systems do not need to be coordinated with the transmission protective systems, as this coordination would not provide reliability benefits to the BES.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

- SAR posted for comment November 20 – December 19, 2013.
- The Standards Committee authorized this posting on September 30, 2014.
- Initial posting of revised standard PRC-001-1.1(ii) on November 5, 2014.

Description of Current Draft

PRC-001-1.1(Xii)[1] is proposed for approval to align the applicability of PRC-001-1.1a with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 – Standards Applicability for Dispersed Generation Resources standards drafting team (SDT) has coordinated with the other SDTs currently reviewing this standard and has recommended revisions to Requirement R3.1 to account for the unique characteristics of dispersed power producing resources.[2] Given the timing of concurrent standards development of PRC, TOP, and IRO projects, PRC-001-1.1a may be retired pursuant to an Implementation Plan of a successor version of PRC-001. If this occurs, PRC-001-1.1(X) will not go into effect. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.

Anticipated Actions	Anticipated Date
Final ballot	January 2015
BOT adoption	February 2015

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

[1] The standard version number included an (X) to indicate the version numbering would be updated, and NERC has since assigned the appropriate version number prior to final ballot.currently includes an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to adoption by the NERC Board of Trustees.

[2] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

A. Introduction

1. **Title:** **System Protection Coordination**

2. **Number:** PRC-001-1.1(Xii)

3. **Purpose:**

   To ensure system protection is coordinated among operating entities.

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Transmission Operators

   4.3. Generator Operators

5. **Effective Date:** January 1, 2007

   See the Implementation Plan for this standardPRC-001-1.1(ii).

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:

R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.

R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.

- Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

Rationale for the Applicability Exclusion in Requirement R3.1

Coordination of new or changes to protective systems associated with dispersed power producing resources identified through Inclusion I4 of the BES definition are typically performed on the interconnecting facilities. New or changes to protective systems associated with these facilities should be coordinated with the TOP as these protective systems typically must be closely coordinated with the transmission protective systems to ensure the overall protection systems operates as designed. While the protective systems implemented on the individual generating units of dispersed power producing resources at these dispersed power producing facilities (i.e. individual wind turbines or solar panels/inverters) may in some cases need to be coordinated with other protective systems within the same dispersed power producing facility, new or changes to these protective systems do not need to be coordinated with the transmission protective systems, as this coordination would not provide reliability benefits to the BES.

R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.

R4. Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:

R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.

R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.

R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

C. Measures

M1. Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic

logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Special Protection Systems in its area. (Requirement 6 Part 1)

M3. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Special Protection Systems. (Requirement 6 Part 2)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
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The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures 2 and 3.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Generator Operators:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

3. Levels of Non-Compliance for Transmission Operators:

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

3.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Failed to provide evidence of coordination when installing new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities as specified in R3.2.

3.4.2 Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

4. Levels of Non-Compliance for Balancing Authorities:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
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1	November 1, 2006	Adopted by the NERC Board of Trustees	Revised
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1.1	September 9, 2013	Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.	
1.1(i)	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
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During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for the Applicability Exclusion in Requirement R3.1

Coordination of new or changes to protective systems associated with dispersed power producing resources identified through Inclusion I4 of the BES definition are typically performed on the interconnecting facilities. New or changes to protective systems associated with these facilities should be coordinated with the TOP as these protective systems typically must be closely coordinated with the transmission protective systems to ensure the overall protection systems operates as designed. While the protective systems implemented on the individual generating units of dispersed power producing resources at these dispersed power producing facilities (i.e. individual wind turbines or solar panels/inverters) may in some cases need to be coordinated with other protective systems within the same dispersed power producing facility, new or changes to these protective systems do not need to be coordinated with the transmission protective systems, as this coordination would not provide reliability benefits to the BES.

A. Introduction

1. Title: Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

2. Number: PRC-019-2

3. Purpose: To verify coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings.

4. Applicability:

4.1. Functional Entities

4.1.1 Generator Owner

4.1.2 Transmission Owner that owns synchronous condenser(s)

4.2. Facilities

For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following:

4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

4.2.2 Individual synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

4.2.3 Generating plant/ Facility consisting of one or more units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

4.2.3.1 This includes individual generating units of the dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition where voltage regulating control for the facility is performed solely at the individual generating unit of the dispersed power producing resources.

4.2.4 Any generator, regardless of size, that is a blackstart unit material to and designated as part of a Transmission Operator's restoration plan.

5. Effective Date:

See the Implementation Plan for PRC-019-2.

B. Requirements

R1. At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system

controls, (including in-service[1] limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Assuming the normal automatic voltage regulator control loop and steady-state system operating conditions, verify the following coordination items for each applicable Facility:

1.1.1. The in-service limiters are set to operate before the Protection System of the applicable Facility in order to avoid disconnecting the generator unnecessarily.

1.1.2. The applicable in-service Protection System devices are set to operate to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits.

R2. Within 90 calendar days following the identification or implementation of systems, equipment or setting changes that will affect the coordination described in Requirement R1, each Generator Owner and Transmission Owner with applicable Facilities shall perform the coordination as described in Requirement R1. These possible systems, equipment or settings changes include, but are not limited to the following *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

- Voltage regulating settings or equipment changes;
- Protection System settings or component changes;
- Generating or synchronous condenser equipment capability changes; or
- Generator or synchronous condenser step-up transformer changes.

C. Measures

M1. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence (such as examples provided in PRC-019 Section G) that it coordinated the voltage regulating system controls, including in-service[2] limiters and protection functions, with the applicable equipment capabilities and settings of the applicable Protection System devices and functions as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed.

M2. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence of the coordination required by the events listed in Requirement R2. This evidence should include dated documentation that demonstrates the specified intervals in Requirement R2 have been met.

[1] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

[2] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention

The following evidence retention periods identify a period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention specified below is shorter than the time since the last compliance audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Owner shall retain evidence of compliance with Requirements R1 and R2, Measures M1 and M2 for six years.

If a Generator Owner or Transmission Owner is found non-compliant, the entity shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last periodic audit report and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years but less than or equal to 5 calendar years plus 4 months after the previous coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years plus 4 months but less than or equal to 5 calendar years plus 8 months after the previous coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years plus 8 months but less than or equal to 5 calendar years plus 12 months after the previous coordination.	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 5 calendar years plus 12 months after the previous coordination.
R2	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 90 calendar days but less than or equal to 100 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 100 calendar days but less than or equal to 110 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 110 calendar days but less than or equal to 120 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 120 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.

E. Regional Variances

None.

F. Associated Documents

"Underexcited Operation of Turbo Generators", AIEE Proceedings T Section 881, Volume 67, 1948, Appendix 1, C. G. Adams and J. B. McClure.

,"Protective Relaying For Power Generation Systems", Boca Raton, FL, Taylor & Francis, 2006, Reimert, Donald

"Coordination of Generator Protection with Generator Excitation Control and Generator Capability", a report of Working Group J5 of the IEEE PSRC Rotating Machinery Subcommittee

"IEEE C37.102-2006 IEEE Guide for AC Generator Protection"

"IEEE C50.13-2005 IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above"

G. Reference

Examples of Coordination

The evidence of coordination associated with Requirement R1 may be in the form of:

- P-Q Diagram (Example in Attachment 1), or
- R-X Diagram (Example in Attachment 2), or
- Inverse Time Diagram (Example in Attachment 3) or,
- Equivalent tables or other evidence

This evidence should include the equipment capabilities and the operating region for the limiters and protection functions

Equipment limits, types of limiters and protection functions which could be coordinated include (but are not limited to):

- Field over-excitation limiter and associated protection functions.
- Inverter over current limit and associated protection functions.
- Field under-excitation limiter and associated protection functions.
- Generator or synchronous condenser reactive capabilities.
- Volts per hertz limiter and associated protection functions.
- Stator over-voltage protection system settings.
- Generator and transformer volts per hertz capability.
- Time vs. field current or time vs. stator current.

NOTE: This listing is for reference only. This standard does not require the installation or activation of any of the above limiter or protection functions.

For this example, the Steady State Stability Limit (SSSL) is the limit to synchronous stability in the under-excited region with fixed field current.

On a P-Q diagram using X_d as the direct axis saturated synchronous reactance of the generator, X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer and V_g as the generator terminal voltage (all values in per-unit), the SSSL can be calculated as an arc with the center on the Q axis with the magnitude of the center and radius described by the following equations

$$C = V^2_g/2*(1/X_s-1/X_d)$$

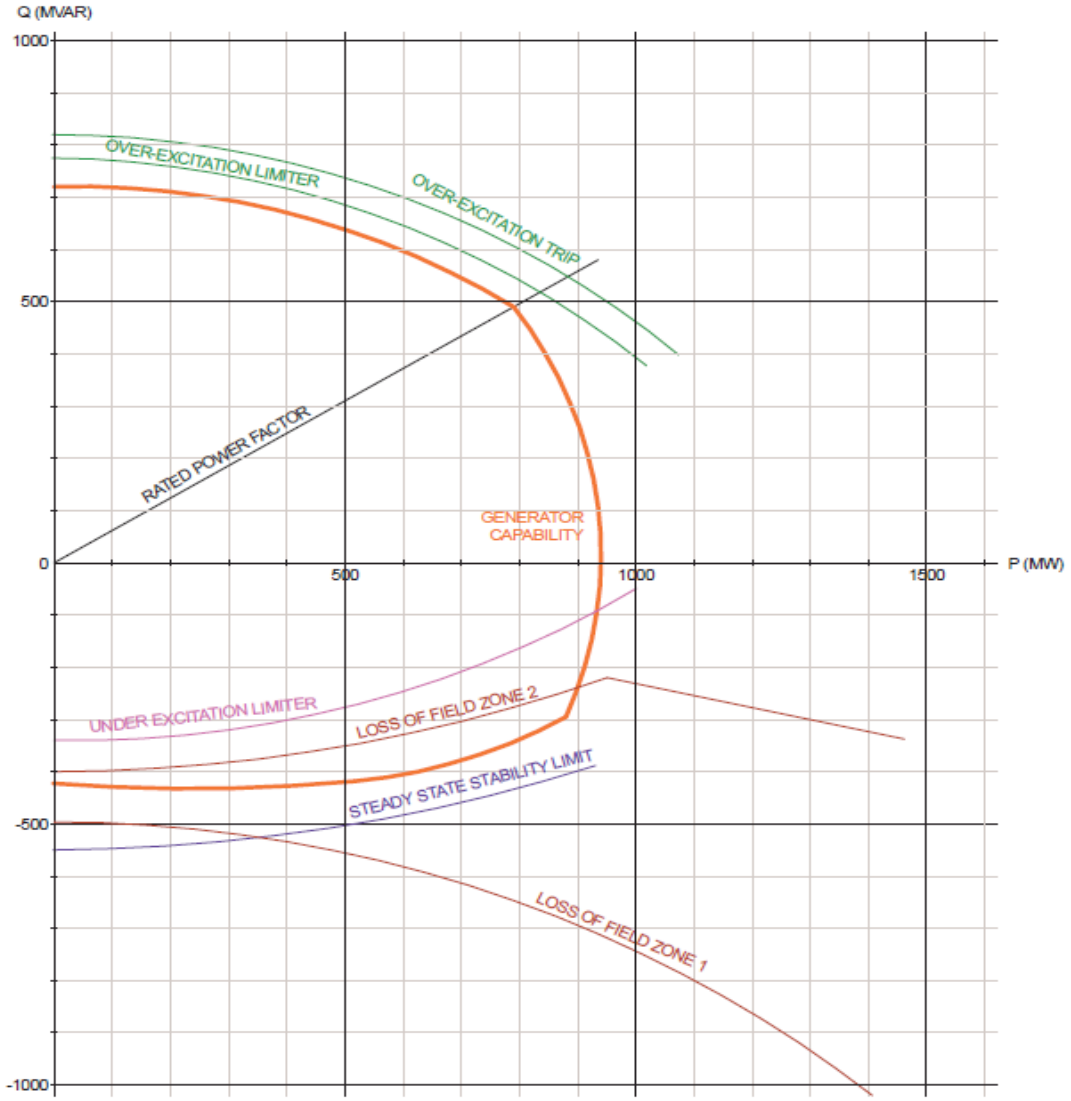
$$R = V^2_g/2*(1/X_s+1/X_d)$$

On an R-X diagram using X_d as the direct axis saturated synchronous reactance of the generator, and X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer the SSSL is an arc with the center on the X axis with the center and radius described by the following equations:

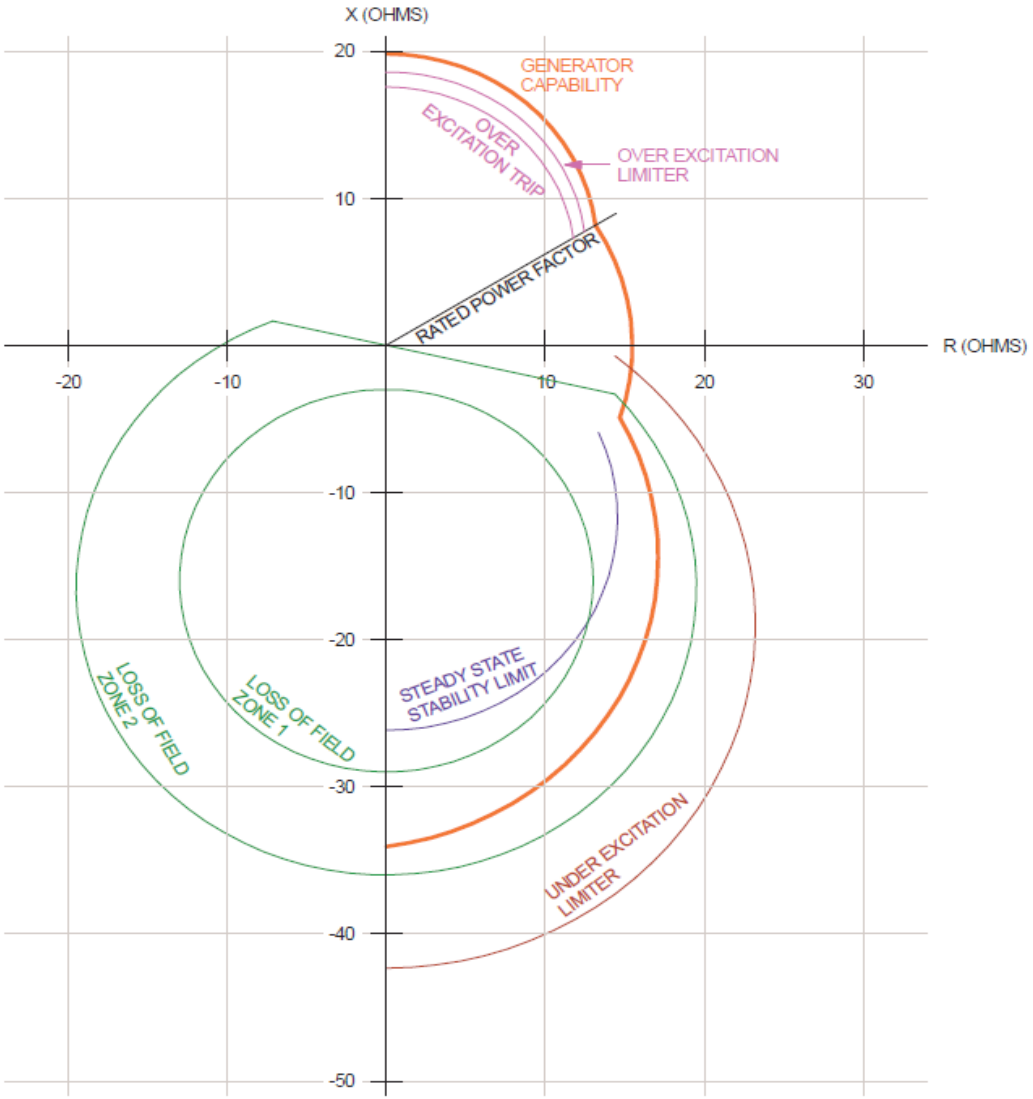
$$C = (X_d-X_s)/2$$

$$R = (X_d+X_s)/2$$

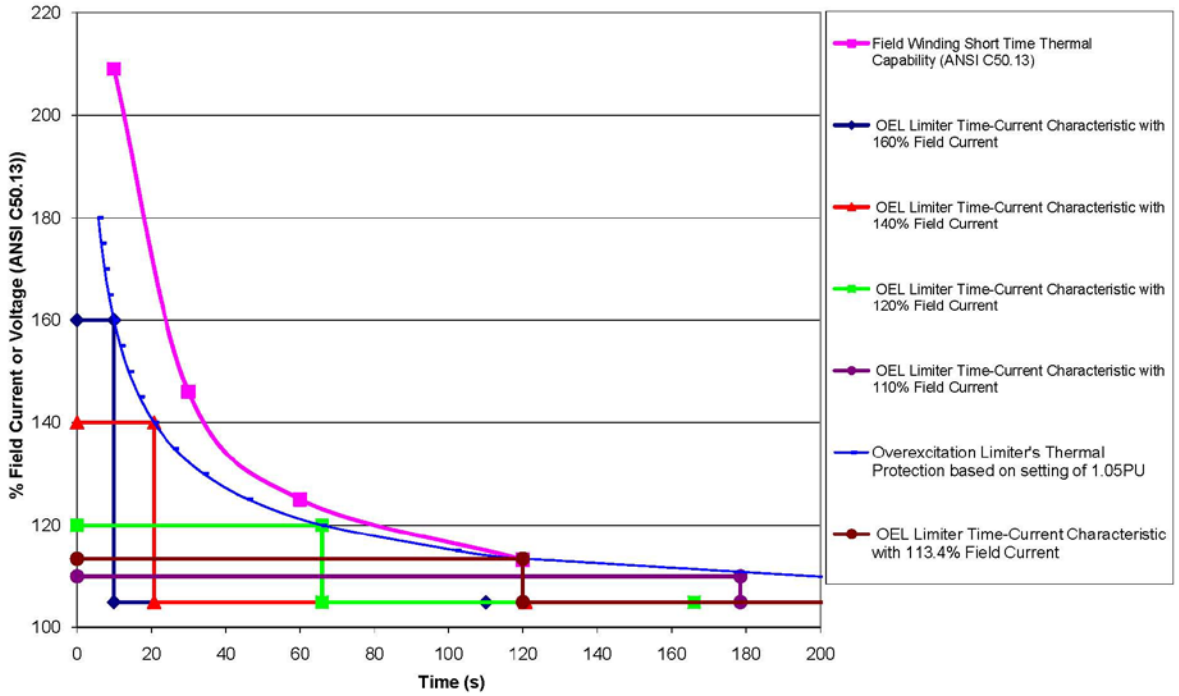
Section G Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency



Section G Attachment 2 – Example of Capabilities, Limiters, and Protection on an R-X Diagram at nominal voltage and frequency



Section G Attachment 3 - Example of Capabilities, Limiters, and Protection on an Inverse Time Characteristic Plot



Version History

Version	Date	Action	Change Tracking
1	February 7, 2013	Adopted by NERC Board of Trustees	New
2	February 12, 2015	Adopted by NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources

Guidelines and Technical Basis

Rationale:
During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Facilities section 4.2.3.1

For those dispersed power producing facilities that only perform voltage regulating control at the individual generating unit level, the SDT believes that coordination should take place at the individual generating unit level of the dispersed power producing resource. These facilities need to consider the Protection Systems at the individual units and their compatibility with the reactive and voltage limitations of the units. Where voltage regulating control is done at an aggregate level, applicability is already included under Facilities section 4.2.3.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

- SAR posted for comment November 20 – December 19, 2013.
- The Standards Committee authorized this posting on September 30, 2014.
- Initial posting of revised standard PRC-019-2 on November 5, 2014.

Description of Current Draft

PRC-019-2 is proposed for approval to align the applicability section of PRC-019-1 with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 – Standards Applicability for Dispersed Generation Resources standards drafting team has recommended revisions to the Facilities section to clarify that facilities that solely regulate voltage at the individual generating unit are subject to the requirements. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.[1]

Anticipated Actions	Anticipated Date
Final ballot	January 2015
BOT adoption	February 2015

[1] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

1. **Title:** Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

2. **Number:** PRC-019-21

3. **Purpose:** To verify coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings.

4. **Applicability:**

   4.1. Functional Entities

   4.1.1 Generator Owner

   4.1.2 Transmission Owner that owns synchronous condenser(s)

   4.2. Facilities

   For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following:

   4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

   4.2.2 Individual synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

   4.2.3 Generating plant/ Facility consisting of one or more units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

   4.2.3.1 This includes individual generating units of the dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition where voltage regulating control for the facility is performed solely at the individual generating unit of the dispersed power producing resources.

Rationale for Facilities section 4.2.3.1

For those dispersed power producing facilities that only perform voltage regulating control at the individual generating unit level, the SDT believes that coordination should take place at the individual generating unit level of the dispersed power producing resource ~~level~~. These facilities need to consider the Protection Systems at the individual units and their compatibility with the reactive and voltage limitations of the units. Where voltage regulating control

is done at an aggregate level, applicability is already included under Facilities section 4.2.3.

4.2.4 Any generator, regardless of size, that is a blackstart unit material to and designated as part of a Transmission Operator's restoration plan.

5. Effective Date:

See the Implementation Plan for PRC-019-2this standard.

~~**5.1.** In those jurisdictions where regulatory approval is required:~~

~~**5.1.1** By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.~~

~~**5.1.2** By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.~~

~~**5.1.3** By the first day of the first calendar quarter, four calendar years following applicable regulatory, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, approval each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.~~

~~**5.1.4** By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.~~

~~**5.2.** In those jurisdictions where regulatory approval is not required:~~

~~**5.2.1** By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.~~

~~**5.2.2** By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.~~

~~5.2.3 By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.~~

~~5.2.4 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.~~

B. Requirements

R1. At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls, (including in-service[2] limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Assuming the normal automatic voltage regulator control loop and steady-state system operating conditions, verify the following coordination items for each applicable Facility:

1.1.1. The in-service limiters are set to operate before the Protection System of the applicable Facility in order to avoid disconnecting the generator unnecessarily.

1.1.2. The applicable in-service Protection System devices are set to operate to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits.

R2. Within 90 calendar days following the identification or implementation of systems, equipment or setting changes that will affect the coordination described in Requirement R1, each Generator Owner and Transmission Owner with applicable Facilities shall perform the coordination as described in Requirement R1. These possible systems, equipment or settings changes include, but are not limited to the following *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

- Voltage regulating settings or equipment changes;
- Protection System settings or component changes;
- Generating or synchronous condenser equipment capability changes; or
- Generator or synchronous condenser step-up transformer changes.

[2] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

C. Measures

M1. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence (such as examples provided in PRC-019 Section G) that it coordinated the voltage regulating system controls, including in-service[3] limiters and protection functions, with the applicable equipment capabilities and settings of the applicable Protection System devices and functions as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed.

M2. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence of the coordination required by the events listed in Requirement R2. This evidence should include dated documentation that demonstrates the specified intervals in Requirement R2 have been met.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention

The following evidence retention periods identify a period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention specified below is shorter than the time since the last compliance audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Owner shall retain evidence of compliance with Requirements R1 and R2, Measures M1 and M2 for six years.

If a Generator Owner or Transmission Owner is found non-compliant, the entity shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer.

[3] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

The Compliance Enforcement Authority shall keep the last periodic audit report and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years but less than or equal to 5 calendar years plus 4 months after the previous coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years plus 4 months but less than or equal to 5 calendar years plus 8 months after the previous coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years plus 8 months but less than or equal to 5 calendar years plus 12 months after the previous coordination.	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 5 calendar years plus 12 months after the previous coordination.
R2	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 90 calendar days but less than or equal to 100 calendar days following the	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 100 calendar days but less than or equal to 110 calendar days following the	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 110 calendar days but less than or equal to 120 calendar days following the	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 120 calendar days following the identification or implementation of a change in equipment

	identification or implementation of a change in equipment or settings that affected the coordination.	identification or implementation of a change in equipment or settings that affected the coordination.	identification or implementation of a change in equipment or settings that affected the coordination.	or settings that affected the coordination.

E. Regional Variances

None.

F. Associated Documents

"Underexcited Operation of Turbo Generators", AIEE Proceedings T Section 881, Volume 67, 1948, Appendix 1, C. G. Adams and J. B. McClure.

,"Protective Relaying For Power Generation Systems", Boca Raton, FL, Taylor & Francis, 2006, Reimert, Donald

"Coordination of Generator Protection with Generator Excitation Control and Generator Capability", a report of Working Group J5 of the IEEE PSRC Rotating Machinery Subcommittee

"IEEE C37.102-2006 IEEE Guide for AC Generator Protection"

"IEEE C50.13-2005 IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above"

Version History

Version	Date	Action	Change Tracking
1	February 7, 2013	Adopted by NERC Board of Trustees	New
1	March 20, 2014	FERC Order issued approving PRC-019-1. (Order becomes effective on 7/1/16.)	
2	February 12, 2015	Adopted by NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources

G. Reference

Examples of Coordination

The evidence of coordination associated with Requirement R1 may be in the form of:

- P-Q Diagram (Example in Attachment 1), or
- R-X Diagram (Example in Attachment 2), or
- Inverse Time Diagram (Example in Attachment 3) or,
- Equivalent tables or other evidence

This evidence should include the equipment capabilities and the operating region for the limiters and protection functions

Equipment limits, types of limiters and protection functions which could be coordinated include (but are not limited to):

- Field over-excitation limiter and associated protection functions.
- Inverter over current limit and associated protection functions.
- Field under-excitation limiter and associated protection functions.
- Generator or synchronous condenser reactive capabilities.
- Volts per hertz limiter and associated protection functions.
- Stator over-voltage protection system settings.
- Generator and transformer volts per hertz capability.
- Time vs. field current or time vs. stator current.

NOTE: This listing is for reference only. This standard does not require the installation or activation of any of the above limiter or protection functions.

For this example, the Steady State Stability Limit (SSSL) is the limit to synchronous stability in the under-excited region with fixed field current.

On a P-Q diagram using X_d as the direct axis saturated synchronous reactance of the generator, X_s as the equivalent reactance between the generator terminals and the

"infinite bus" including the reactance of the generator step-up transformer and V_g as the generator terminal voltage (all values in per-unit), the SSSL can be calculated as an arc with the center on the Q axis with the magnitude of the center and radius described by the following equations

$$C = V^2_g/2*(1/X_s-1/X_d)$$

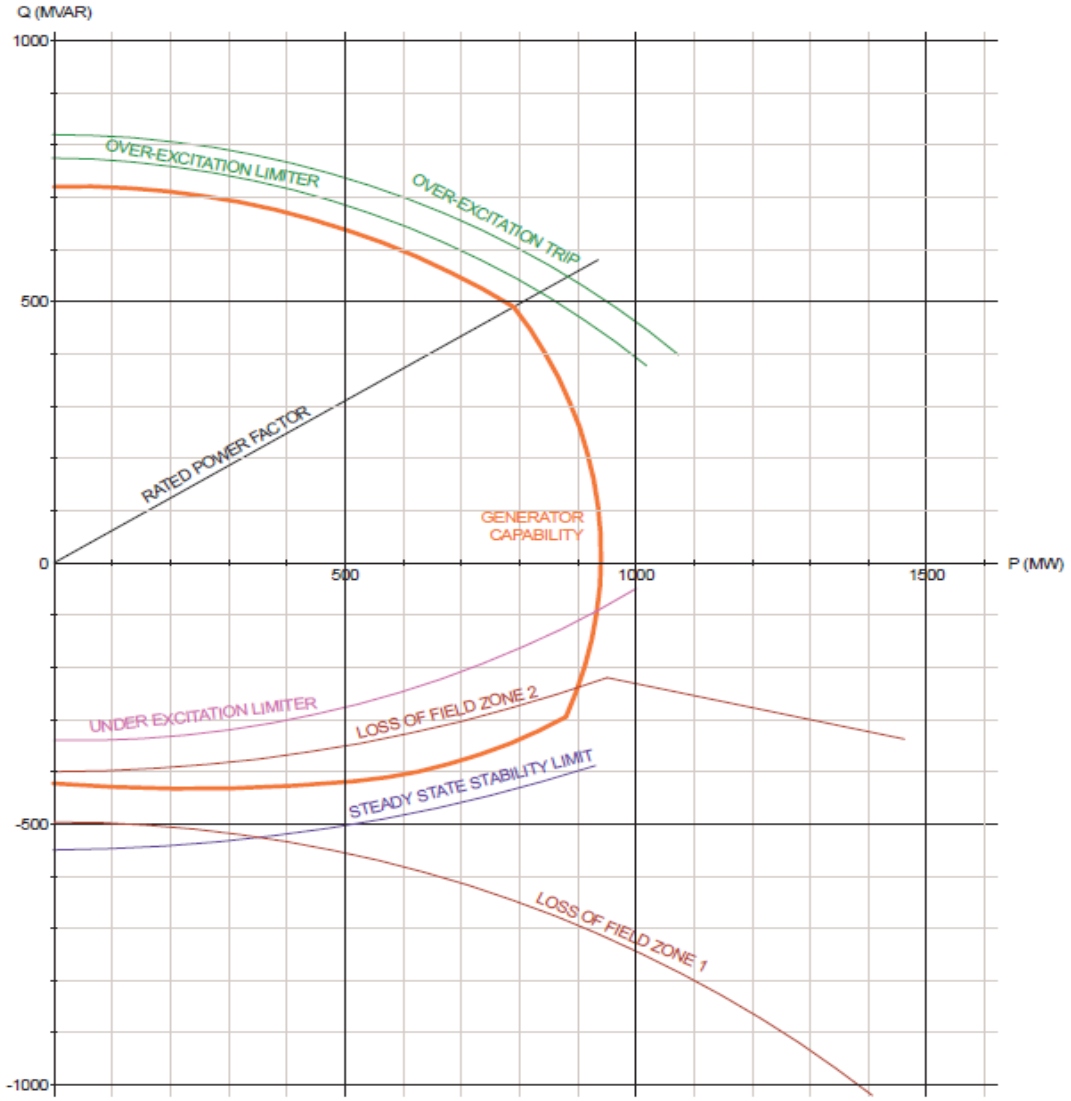
$$R = V^2_g/2*(1/X_s+1/X_d)$$

On an R-X diagram using X_d as the direct axis saturated synchronous reactance of the generator, and X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer the SSSL is an arc with the center on the X axis with the center and radius described by the following equations:

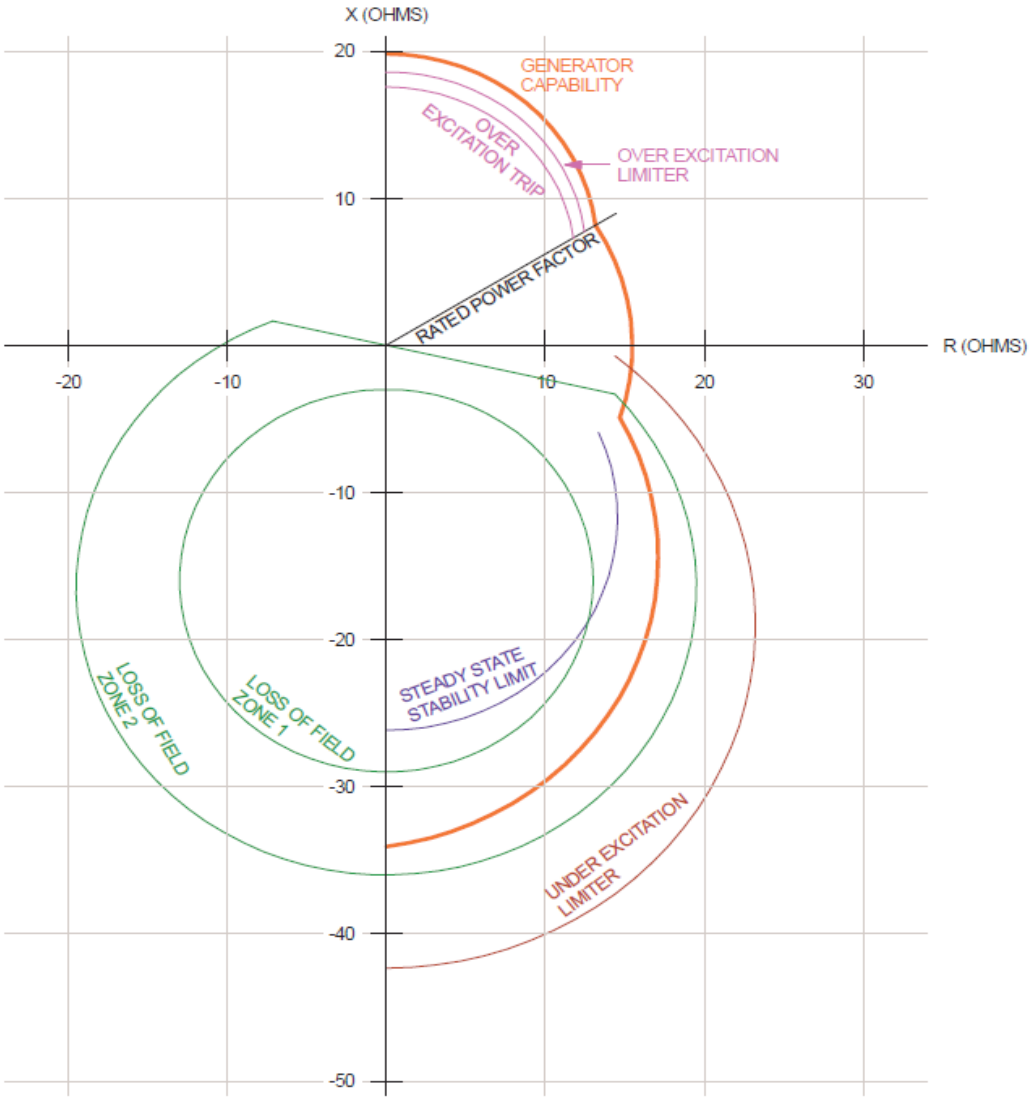
$$C = (X_d-X_s)/2$$

$$R = (X_d+X_s)/2$$

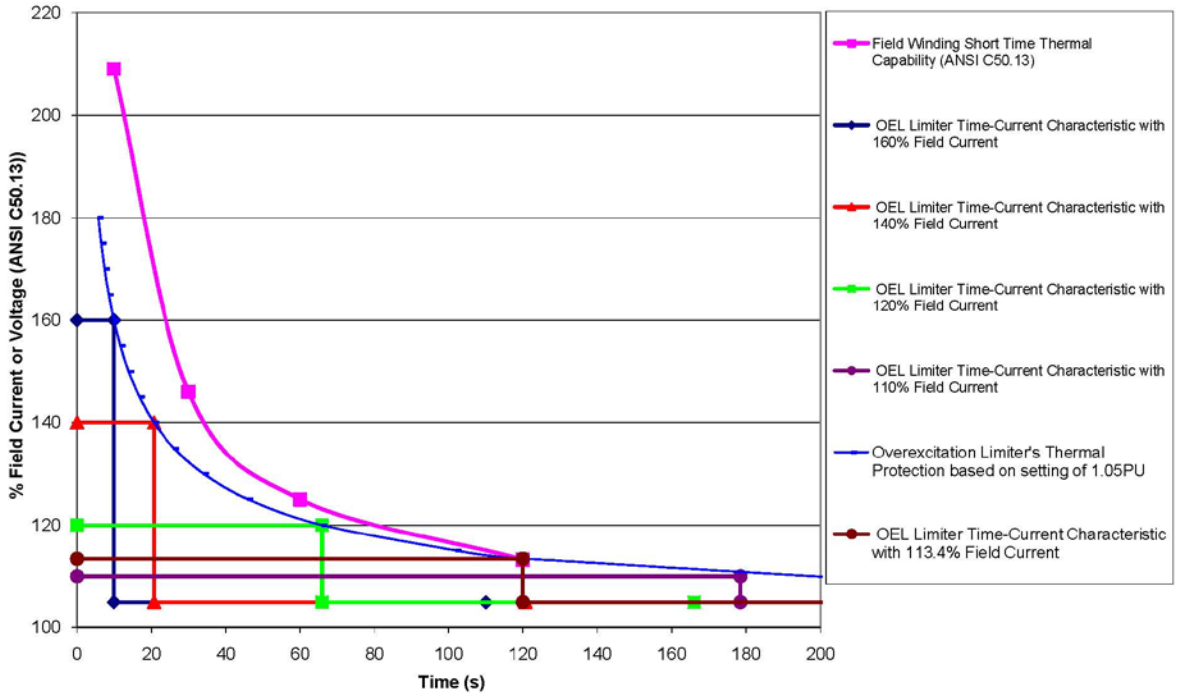
Section G Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency



Section G Attachment 2 – Example of Capabilities, Limiters, and Protection on an R-X Diagram at nominal voltage and frequency



Section G Attachment 3 - Example of Capabilities, Limiters, and Protection on an Inverse Time Characteristic Plot



Guidelines and Technical Basis

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Facilities section 4.2.3.1

For those dispersed power producing facilities that only perform voltage regulating control at the individual generating unit level, the SDT believes that coordination should take place at the individual generating unit level of the dispersed power producing resource. These facilities need to consider the Protection Systems at the individual units and their compatibility with the reactive and voltage limitations of the units. Where voltage regulating control is done at an aggregate level, applicability is already included under Facilities section 4.2.3.

A. Introduction

1. **Title:** **Generator Frequency and Voltage Protective Relay Settings**

2. **Number:** PRC-024-2

3. **Purpose:** Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.

4. **Applicability:**

   4.1. Generator Owner

5. **Effective Date:**

   See the Implementation Plan for PRC-024-2.

B. Requirements

R1. Each Generator Owner that has generator frequency protective relaying[1] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the "no trip zone" of PRC-024 Attachment 1, subject to the following exceptions:[2] *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

R2. Each Generator Owner that has generator voltage protective relaying[1] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a

[1] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

[2] For frequency protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to frequency protective relays applied on the individual generating unit of the dispersed power producing resources, as well as frequency protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.

voltage excursion (at the point of interconnection[3]) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2.[4] If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner's study. Requirement R2 is subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

R3. Each Generator Owner shall document each known regulatory or equipment limitation[5] that prevents an applicable generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:

- Identification of a regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.
- Replacement of the equipment causing the limitation with equipment that removes the limitation.

[3] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

[4] For voltage protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to voltage protective relays applied on the individual generating unit of the dispersed power producing resources, as well as voltage protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.

[5] Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.

- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.

R4. Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets or other documentation.

M2. Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, dynamic simulation studies or other documentation.

M3. Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.

M4. Each Generator Owner shall have evidence that it communicated applicable generator protective relay trip settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases, the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner shall retain evidence of compliance with Requirement R1 through R4; for 3 years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, the Generator Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generating unit, failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit, failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2. OR

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	The Generator Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.
R4	The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner failed to provide its generator protection trip settings within 150 calendar days of any change to those trip settings. OR The Generator Owner failed to provide trip settings within 150 calendar days of a written request.

E. Regional Variances

None

F. Associated Documents

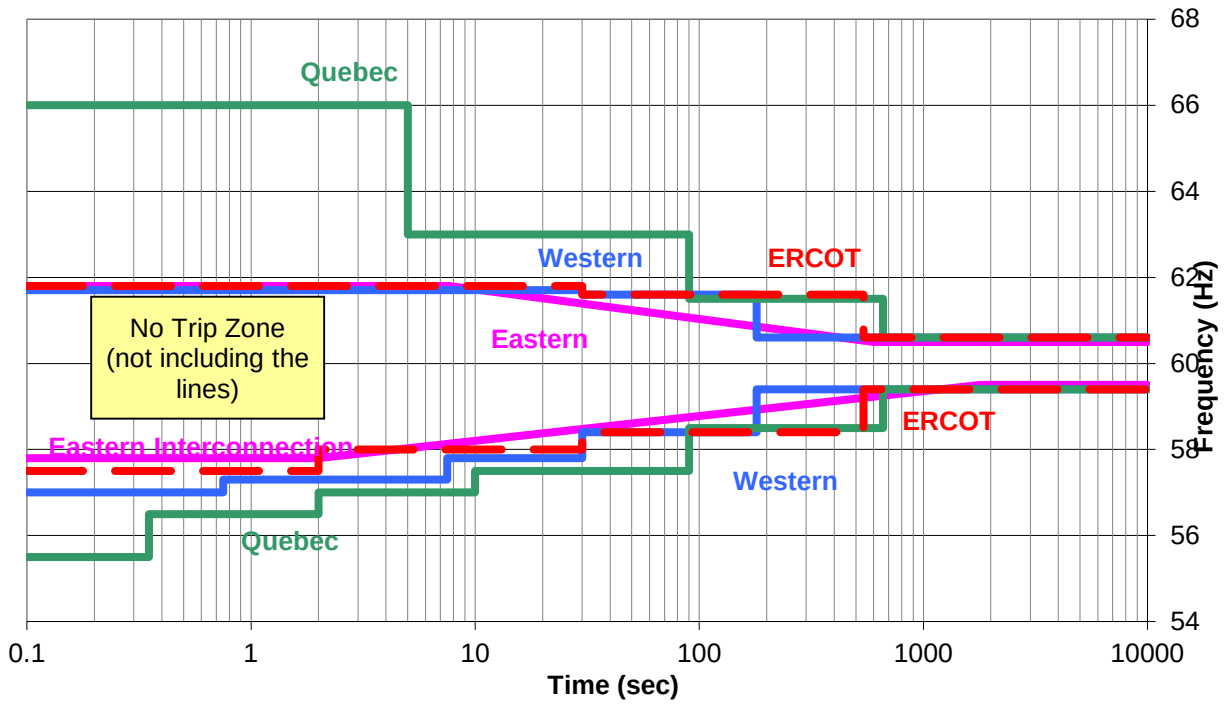
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G. References

1. "The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF)," dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

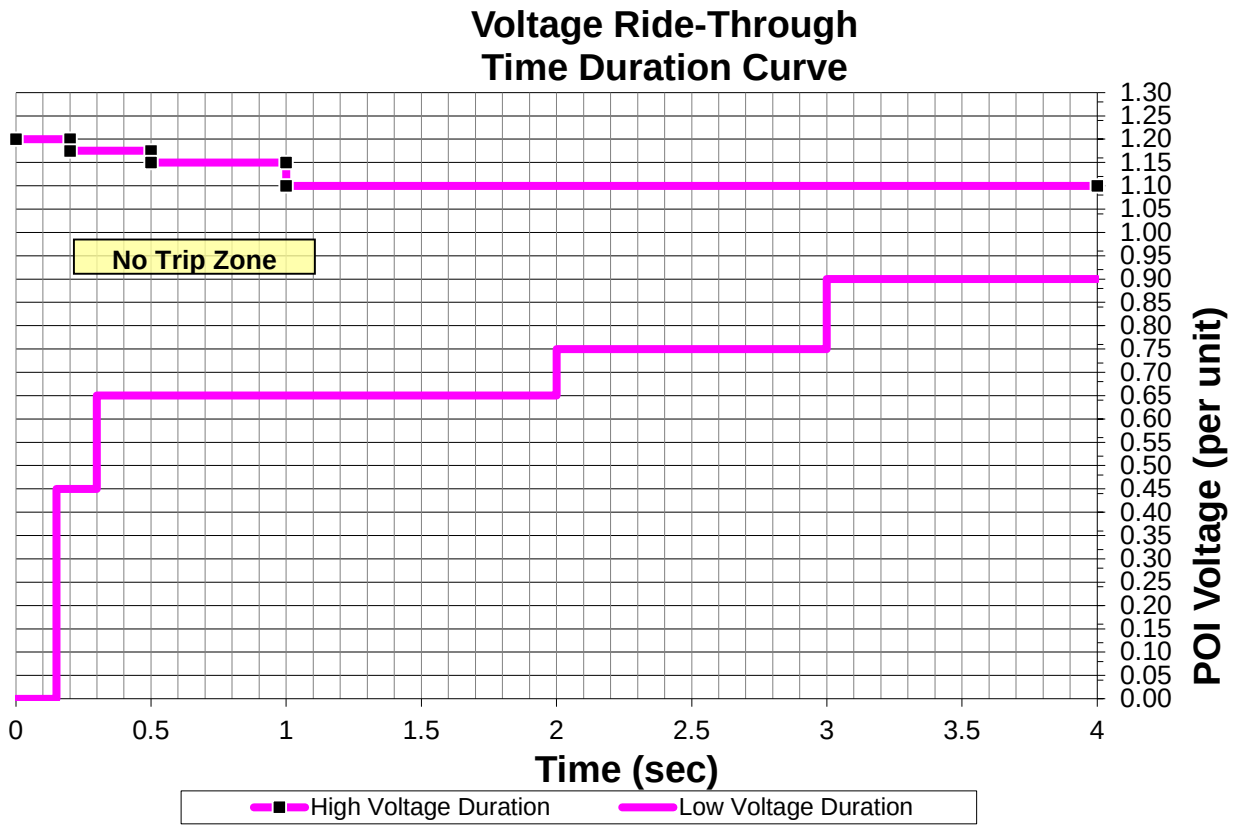
Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (Sec)
>66.0	Instantaneous trip	<55.5	Instantaneous trip
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.5	Instantaneous trip
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024— Attachment 2



Ride Through Duration:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	**Time (sec)**	**Voltage (pu)**	**Time (sec)**
≥1.200	Instantaneous trip	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
    a. All of the units connected to the same transformer are online and operating.
    b. All of the units are at full nameplate real-power output.
    c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
    d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

Version History

Version	Date	Action	Change Tracking
1	May 9, 2013	Adopted by the NERC Board of Trustees	
2	February 12, 2015	Adopted by the NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources

Guidelines and Technical Basis

Rationale:
During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Footnotes 4 and 6

The SDT has determined it is appropriate to require that protective relay settings applied on both the individual generating units and aggregating equipment (including any non-Bulk Electric System collection system equipment) are set respecting the “no-trip zone” referenced in the requirements to maintain reliability of the BES. If any of the protective relay settings applied on these elements of the facility were to be excluded from this standard, the potential would exist for portions of or the entire generating capacity of the dispersed power producing facility to be lost during a voltage or frequency excursion.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

- SAR posted for comment November 20 – December 19, 2013.
- The Standards Committee authorized this posting on September 30, 2014.
- Initial posting of revised standard PRC-024-2 on November 5, 2014.

Description of Current Draft

PRC-024-21(X)[1] is proposed for approval to align the applicability section of PRC-024-1 with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 –Standards Applicability for Dispersed Generation Resources standards drafting team recommended changes to the requirements addressing the scope of applicability and also recommended changes to the Reliability Standard Audit Worksheet to address documentation options. Given the timing of concurrent standards development of PRC projects, PRC-024-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-024. If this occurs, PRC-024-1(X) will not go into effect. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.[2]

Anticipated Actions	Anticipated Date
Final ballot	January 2015
BOT adoption	February 2015

[1] The standard version number included an (X) to indicate the version numbering would be updated, and NERC has since assigned the appropriate version number prior to final ballot.currently had includes an (X) to indicate the version numbering will be updated, and . Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will since assign the appropriate version number prior to adoption by the NERC Board of Trustees.

[2] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

1. **Title:** **Generator Frequency and Voltage Protective Relay Settings**
2. **Number:** PRC-024-21(X)
3. **Purpose:** Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.
4. **Applicability:**

   4.1. Generator Owner

5. **Effective Date:**

   See the Implementation Plan for PRC-024-2this standard.

In those jurisdictions where regulatory approval is required:

By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

In those jurisdictions where regulatory approval is not required:

By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

B. Requirements

R1. Each Generator Owner that has generator frequency protective relaying[3] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the "no trip zone" of PRC-024 Attachment 1, subject to the following exceptions:[4] *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

Rationale for Footnotes 24 and 46

The SDT has determined it is appropriate to require that protective relay settings applied on both the individual generating units and aggregating equipment (including any non-Bulk Electric System collection system equipment) are set respectingwithin the "no trip zone" referenced in the requirements to maintain reliability of the BES. If any of the protective relay settings applied on these elements of the facility were to be excluded from this standard, the potential would exist for portions of or the entire generating capacity of the dispersed power producing facility to be lost during a voltage or frequency excursion.

R2. Each Generator Owner that has generator voltage protective relaying[3] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a

[3] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

[4] For frequency protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to frequency protective relays applied on the individual generating unit of the dispersed power producing resources, as well as frequency protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.

voltage excursion (at the point of interconnection[5]) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2.[6] If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner's study. Requirement R2 is subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

R3. Each Generator Owner shall document each known regulatory or equipment limitation[7] that prevents an applicable generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:

- Identification of a regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.

[5] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

[6] For voltage protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to voltage protective relays applied on the individual generating unit of the dispersed power producing resources, as well as voltage protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.

[7] Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.

- Replacement of the equipment causing the limitation with equipment that removes the limitation.
- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.

R4. Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets or other documentation.

M2. Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, dynamic simulation studies or other documentation.

M3. Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.

M4. Each Generator Owner shall have evidence that it communicated applicable generator protective relay trip settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases, the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where

the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner shall retain evidence of compliance with Requirement R1 through R4; for 3 years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, the Generator Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generating unit, failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit, failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	OR The Generator Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.
R4	The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner failed to provide its generator protection trip settings within 150 calendar days of any change to those trip settings. OR The Generator Owner failed to provide trip settings within 150 calendar days of a written request.

E. Regional Variances

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
1	May 9, 2013	Adopted by the NERC Board of Trustees	

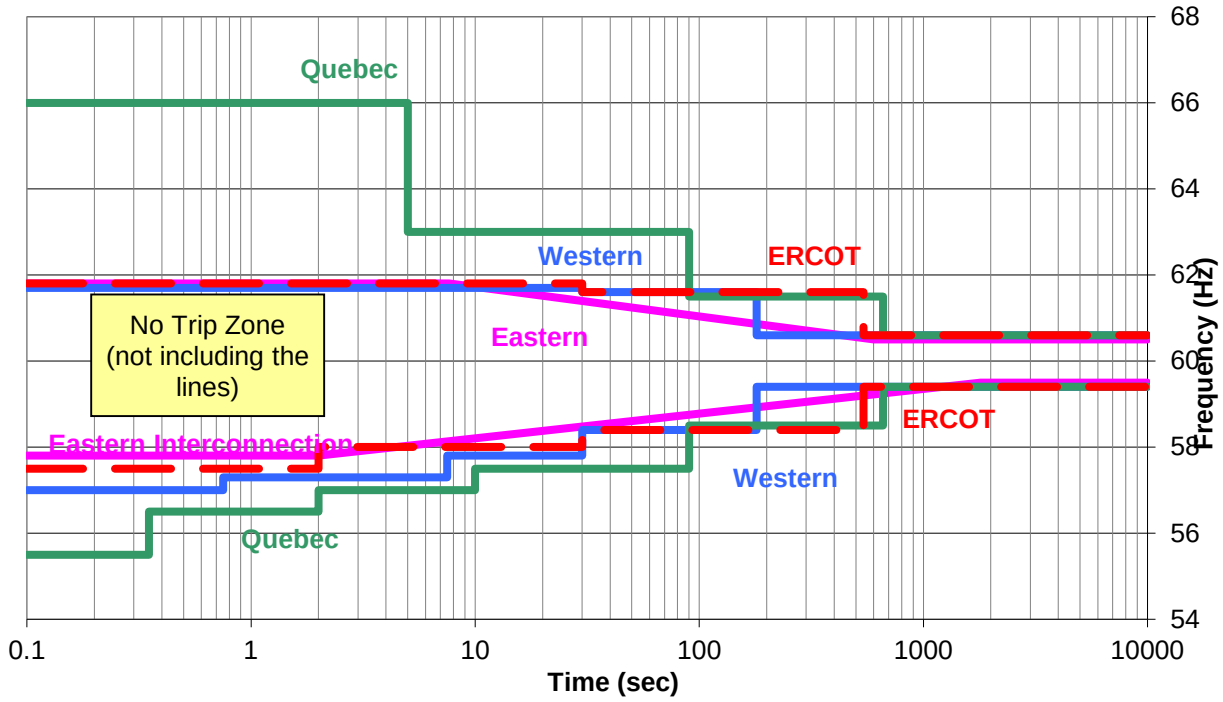
~~1~~	~~March 20, 2014~~	~~FERC Order issued approving PRC-024-1. (Order becomes effective on 7/1/16.)~~	
2	February 12, 2015	Adopted by the NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources

G. References

1. "The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF)," dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

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Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

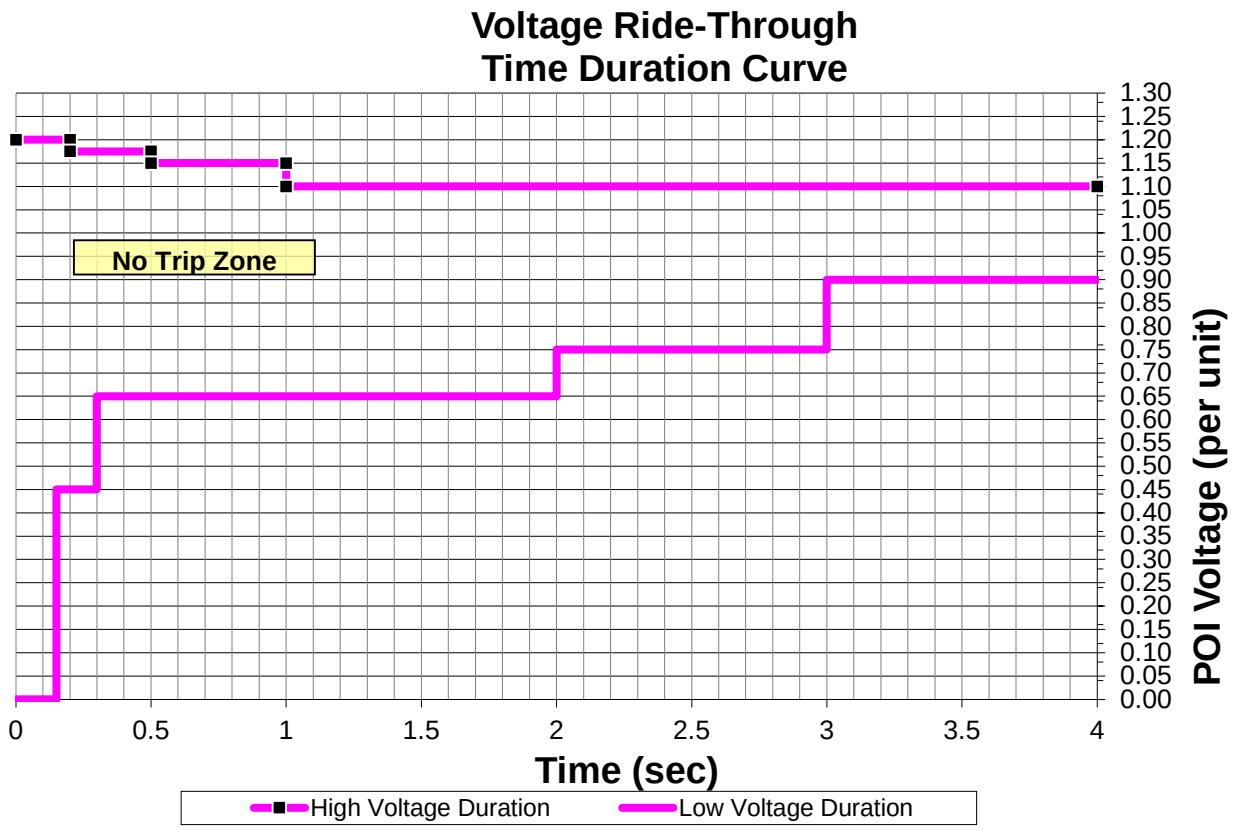
Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (Sec)
>66.0	Instantaneous trip	<55.5	Instantaneous trip
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.5	Instantaneous trip
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024— Attachment 2



Ride Through Duration:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	**Time (sec)**	**Voltage (pu)**	**Time (sec)**
≥1.200	Instantaneous trip	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
    a. All of the units connected to the same transformer are online and operating.
    b. All of the units are at full nameplate real-power output.
    c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
    d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

Guidelines and Technical Basis

Rationale:
During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Footnotes 4 and 6

The SDT has determined it is appropriate to require that protective relay settings applied on both the individual generating units and aggregating equipment (including any non-Bulk Electric System collection system equipment) are set respecting the "no-trip zone" referenced in the requirements to maintain reliability of the BES. If any of the protective relay settings applied on these elements of the facility were to be excluded from this standard, the potential would exist for portions of or the entire generating capacity of the dispersed power producing facility to be lost during a voltage or frequency excursion.

Exhibit B

Implementation Plans

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Dispersed Generation Resources
PRC-001-1.1(ii)

Standards Involved

Approval:

- PRC-001-1.1(ii) – System Protection Coordination

Retirement:

- PRC-001-1.1a – System Protection Coordination (or a successor version of PRC-001-1.1 such as PRC-001-1.1(i))

Prerequisite Approvals:

N/A

Background

In light of the adoption of a revised Bulk Electric System (BES) definition by the NERC Board of Trustees, changes to the applicability of certain Reliability Standards, including PRC-001, are necessary to align the standards with the implementation of the revised BES definition. The standard drafting team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Generation Resources has modified the applicability section and requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed power producing resources in order to ensure the applicability of the standards is consistent with the reliable operation of the BES.[1]

General Considerations

PRC-001-1.1(ii) is proposed for approval to align the applicability of PRC-001-1.1 with the revised definition of the BES. Specifically, the SDT has coordinated with the other SDTs currently reviewing this standard and has recommended revisions to Requirement R3.1 to account for the unique characteristics of dispersed power producing resources.

Effective Date

PRC-001-1.1(ii) shall become effective immediately after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable

[1] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

The existing standard, PRC-001-1.1 (or a successor version of PRC-001-1.1 such as PRC-001-1.1(i)), shall be retired at midnight of the day immediately prior to the Effective Date of PRC-001-1.1(ii).

Applicability:

This standard applies to the following functional entities:

- Transmission Operator
- Generator Operator
- Balancing Authority

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Implementation Plan

Dispersed Generation Resources
PRC-019-2

Standards Involved

Approval:

- PRC-019-2 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Retirement:

- PRC-019-1 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Prerequisite Approvals:

N/A

Background

In light of the adoption of a revised Bulk Electric System (BES) definition by the NERC Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-019, are necessary to align the standards with the implementation of the revised BES definition. The standard drafting team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Generation Resources has modified the applicability section and requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed power producing resources in order to ensure the applicability of the standards is consistent with the reliable operation of the BES.[1]

General Considerations

PRC-019-2 is proposed for approval to align the applicability section of PRC-019-1 with the revised definition of the BES. Specifically, the SDT has recommended revisions to the Facilities section to clarify that facilities that solely regulate voltage at the individual generating unit are subject to the requirements.

Effective Date

[1] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

PRC-019-2 shall become effective on the later of the first day following the Effective Date of PRC-019-1 or immediately after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the later of the first day following the Effective Date of PRC-019-1 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

The existing standard, PRC-019-1, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-019-2.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner that owns synchronous condenser(s)
- Generator Owner

Implementation Plan

All aspects of the Implementation Plan for PRC-019-1 will remain applicable to PRC-019-2 and are incorporated here by reference.

Cross References

The Implementation Plan for the revised definition of "Bulk Electric System" is available here.

The Implementation Plan for PRC-019-1 is available here.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Dispersed Generation Resources
PRC-024-2

Standards Involved

Approval:

- PRC-024-2 – Generator Frequency and Voltage Protective Relay Settings

Retirement:

- PRC-024-1 – Generator Frequency and Voltage Protective Relay Settings

Prerequisite Approvals:

N/A

Background

In light of the adoption of a revised Bulk Electric System (BES) definition by the NERC Board of Trustees, changes to the applicability of certain Reliability Standards, including PRC-024, are necessary to align the standards with the revised BES definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Generation Resources has modified the applicability section or requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the BES.

General Considerations

PRC-024-2 is proposed for approval to align the applicability of PRC-024-1 with the revised definition of the BES. Specifically, the SDT recommended changes to the requirements addressing the scope of applicability and also recommended changes to the Reliability Standard Audit Worksheet to address documentation options.

Effective Date

PRC-024-2 shall become effective on the later of the first day following the Effective Date of PRC-024-1 or immediately after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the later of the first day following the Effective Date of PRC-024-1 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

The existing standard, PRC-024-1, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-024-2.

Applicability:

This standard applies to the following functional entities:

- Generator Owner

Implementation Plan

All aspects of the Implementation Plan for PRC-024-1 will remain applicable to PRC-024-2 and are incorporated here by reference.

Cross References

The Implementation Plan for the revised definition of "Bulk Electric System" is available here.

The Implementation Plan for PRC-024-1 is available here.

Exhibit C

Order No. 672 Criteria

Exhibit C
Order No. 672 Criteria

In Order No. 672,[1] the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed Reliability Standards has met or exceeded the criteria.

1. Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.[2]

The proposed Reliability Standards continue to achieve specific reliability goals and have included targeted language to clarify the applicability with respect to dispersed power producing resources. Proposed Reliability Standard PRC-001-1.1(ii) is designed to ensure that system protection is coordinated among operating entities. The purpose of proposed Reliability Standard PRC-019-2 is to verify coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings.

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[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[2] Order No. 672 at P 321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection.

Order No. 672 at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.

The purpose of Reliability Standard PRC-024-2 is to ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.

2. Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.[3]

Proposed Reliability Standard PRC-001-1.1(ii) applies to Balancing Authorities, Transmission Operators, and Generator Operators. Proposed Reliability Standard PRC-019-2 applies to Generator Owners and Transmission Owners that own synchronous condenser(s). Proposed Reliability Standard PRC-024-2 applies to Generator Owners. All of the proposed Reliability Standards have improved the clarity of the coverage with respect to dispersed generation resources and are, therefore, more clear than the prior versions. Other substantive Requirements in the Reliability Standards remain unchanged.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[4]

The VRFs and VSLs for each of the proposed standards comport with NERC and Commission guidelines related to their assignment. The assignment of the severity level for each VSL is consistent with the corresponding Requirement and the VSLs should ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous

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[3] Order No. 672 at P 322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.

Order No. 672 at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

[4] Order No. 672 at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

Because the Requirements contained in proposed Reliability Standards track with those contained in the already approved or proposed versions of the Reliability Standards, the standards drafting team determined that no revisions were necessary to the VSLs and VRFs for the proposed Reliability Standards. For these reasons, the proposed Reliability Standards include clear and understandable consequences in accordance with Order No. 672.

4. A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non preferential manner. [5]

The proposed Reliability Standards contain Measures that support each requirement by clearly identifying what is required and how the requirement will be enforced. The Measures for the proposed Reliability Standards remain unchanged from previous versions. These Measures help provide clarity regarding how the requirements will be enforced, and ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.[6]

The proposed Reliability Standards achieve the reliability goals effectively and efficiently in accordance with Order No. 672. The proposed Reliability Standards improve reliability by ensuring the equipment utilized to aggregate individual dispersed generation units to a common

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[5] Order No. 672 at P 327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.

[6] Order No. 672 at P 328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.

point of interconnection with the Bulk-Power System is operated and maintained as required by the NERC Reliability Standards.

6. Proposed Reliability Standards cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.[7]

The proposed Reliability Standards do not reflect a "lowest common denominator" approach. The changes reflected in the Proposed Reliability Standards are supported by technical analysis in the Technical White Paper in Exhibit C to the February 6 Petition and are targeted to a specific issue and balance the applicability of the coverage of the proposed Reliability Standards with the reliability needs specific to dispersed generation resources.

7. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. Proposed Reliability Standards should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standards.[8]

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[7] Order No. 672 at P 329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator" — if such practice does not adequately protect Bulk-Power System reliability. Although FERC will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.

Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.

[8] Order No. 672 at P 331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.

The proposed Reliability Standards apply throughout North America and do not favor one geographic area or regional model.

8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[9]

The proposed Reliability Standards do not restrict the available transmission capability or limit use of the Bulk-Power System in a preferential manner.

9. The implementation time for the proposed Reliability Standard is reasonable.[10]

The proposed effective dates for the proposed Reliability Standards are just and reasonable and appropriately balance the urgency in the need to implement the standards against the reasonableness of the time allowed for those who must comply to develop necessary procedures or other relevant capability. The proposed effective dates are explained in the proposed Implementation Plans, attached as Exhibit B. The Implementation Plans reflect timing needed to align changes related to dispersed power producing resources with the version being modified. The timing is also set to become effective on an expedited basis to parallel the implementation of the revised definition of Bulk Electric System. The Implementation Plans also account for ongoing implementation of prior versions as necessary.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[11]

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[9] Order No. 672 at P 332. As directed by section 215 of the FPA, FERC itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.

[10] Order No. 672 at P 333. In considering whether a proposed Reliability Standard is just and reasonable, FERC will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.

[11] Order No. 672 at P 334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a

The proposed Reliability Standards were developed in accordance with NERC's Commission-approved, ANSI- accredited processes for developing and approving Reliability Standards. Exhibit D includes a summary of the Reliability Standards development proceedings, and details the processes followed to develop the standards.

These processes included, among other things, multiple comment periods, pre-ballot review periods, and balloting periods. Additionally, all meetings of the drafting team were properly noticed and open to the public.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[12]

NERC has identified no competing public interests regarding the request for approval of these proposed Reliability Standards. No comments were received that indicated the proposed Standards conflict with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[13]

No other negative factors relevant to whether the proposed Reliability Standards are just and reasonable were identified.

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proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.

[12] Order No. 672 at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

[13] Order No. 672 at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.

Exhibit D

Summary of Development History and Complete Record of Development of Proposed Reliability Standards

Exhibit D: Summary of Development History

The development record for the proposed Reliability Standards is summarized below.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO[1]. The technical expertise of the ERO is derived from the standard drafting team. For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the standard drafting team members is included in Exhibit E.

II. Standard Development History

A. Standard Authorization Request ("SAR") Development

A SAR for Project 2014-01 Standards Applicability for Dispersed Generation Resources ("DGR") was posted for a 30-day formal comment period from November 20, 2013 through December 19, 2013. The NERC Standards Committee approved the revised SAR on October 17, 2013.

B. First Posting - Formal Comment Period, Initial Ballots

Proposed Reliability Standards, PRC-001-1.1(X), PRC-019-2 and PRC-024-1 (X), were posted for a 45-day public comment period from November 5, 2014 December 23, 2014 with an initial ballot conducted from December 10, 2014 through December 23, 2014. The initial ballot for PRC-001-1.1 (X) achieved 79.38% quorum, and an approval of 92.69%, PRC-019-2 achieved 79.72% quorum, and an approval of 93.55%, and PRC-024-1 (X) achieved 79.60% quorum, and an approval of 93.67%. There were 25 sets of comments, including comments from

[1] Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824(d) (2) (2012).

approximately 98 different individuals and approximately 69 companies, representing all 10 industry segments.

The standard drafting team considered stakeholder comments regarding the proposed Reliability Standards and made modifications based on those comments. A summary of the responses to comments and changes made is included in the Consideration of Comments for the posting.

C. Final Ballots

Proposed Reliability Standards PRC-001-1.1 (ii), PRC-019-2 and PRC-024-2 were posted for a 10-day final ballot period from January 13, 2015 through January 22, 2015. PRC-001-1.1 (ii) achieved 89.27% quorum, and an approval of 93.99%, PRC-019-2 achieved 89.30% quorum, and an approval of 94.03% and PRC-024-2 achieved 89.52% quorum, and an approval of 95.82%.

D. Board of Trustees Adoption

Proposed Reliability Standards PRC-001-1.1 (ii), PRC-019-2 and PRC-024-2 were adopted by the NERC Board of Trustees on February 12, 2015.

Project 2014-01 Standards Applicability for Dispersed Generation Resources

Related Files

Status

A final ballot for **PRC-005-5- Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance** is open through **8 p.m. Eastern on March 11, 2015**. Voting results will be posted and announced after the ballot window closes. If approved, the standard will be submitted to the NERC Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Board Adopted November 13, 2014 - PRC-004-2.1(i)a, PRC-004-4, PRC-005-2(i), and PRC-005-3(i)

Filed with FERC

Order Effective

Enforcement Date

Background:

The Standards Authorization Request (SAR) asks that the applicability section of certain Reliability Standards that apply to a Generator Owner (GO)/Generator Operator (GOP) or the requirements of certain GO/GOP Reliability Standards be reviewed, and where appropriate revised to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk Electric System (BES). Dispersed generation resources are those resources that are small-scale power generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include but are not limited to solar, geothermal, energy storage, flywheels, wind, micro-turbines, and fuel cells.

This request is related to the revised definition of the Bulk Electric System (BES) from Project 2010-17, and it is desirable to complete any revisions determined to be necessary so that revisions are approved by the Board of Trustees and applicable regulatory agencies prior to the effective date for newly identified elements under the revised BES definition. This effective date is expected to be July 1 2016, although it is possible that regulatory action could change the date.

Draft	Actions	Dates	Results	Consideration of Comments

Errata Change:

On November 13, 2014, the NERC Board of Trustees (Board) adopted PRC-006-2 PRC 004-2.1(i)a, PRC-004-4, PRC-005-2(i), and PRC-005-3(i). Each of these standards, or its associated documents, contain inadvertent errors that needed to be corrected prior to filing with applicable regulatory authorities. The standards referenced the implementation plan in the Effective Date section. As a result, there are no associated changes to the standard with the corrections.

Each error and how the corrections meet the required elements of an errata change are described below.

References to "(X)" in Implementation Plans for PRC-004-2(i)a, PRC-005-2(i), and PRC-005-3(i) needed to be changed to align the standard versions with the updated NERC standards numbering convention.

The Effective Date language in the Implementation Plan for PRC-004-4 needed to be corrected to properly sequence version 4 to become effective concurrently with or after version 3. The implementation plan provided for an immediate effective date, which in some scenarios could make version 4 effective prior to version 3, which has a 12 month period after approval before it becomes effective. The drafting team intended to sequence the standards to ensure that version 4 did not go into effect prior to version 3, but went into effect immediately upon approval if version 3 was effective.

A correction was also needed to ensure version 4 becomes effective on the later of the effective date of PRC-004-3 or the date that PRC-004-4 is approved by an applicable governmental authority. A conforming correction to reference the effective date of PRC-004-3 rather than "12 months following the approval of PRC-004-3" to make sure that the implementation timing for PRC-004-3 is properly cross referenced was also needed.

Implementation Plans

PRC-005-2(i)
Clean | Redline to Last Approved

PRC-005-3(i)
Clean | Redline to Last Approved

PRC-004-2.1(i)
Clean | Redline to Last Approved

PRC-004-4
Clean | Redline to Last Approved

Final Draft **PRC-005-5** Clean | Redline to Last Posted | Redline to PRC-005-4 **Implementation Plan** Clean | Redline to Last Posted **Supporting Documents** SAR	Final Ballot Info>> Vote>>	03/02/15 – 03/11/15		
Final Drafts **PRC-001-1.1(ii)** Clean **(28)** | Redline to Last Posted **(29)** | Redline to PRC-001-1.1 **(30)** **PRC-019-2** Clean **(31)** | Redline to Last Posted **(32)** | Redline to PRC-019-1 **(33)** **PRC-024-2** Clean **(34)** | Redline to Last Posted **(35)** | Redline to PRC-024-1 **(36)** **Implementation Plans** **PRC-001-1.1(ii)** Clean	Final Ballots Info>> **(44)** Vote>> (Closed)	01/13/15 - 01/22/15	Summary>> **(45)** Ballot Results PRC-001-1.1(ii)>> **(46)** PRC-019-2>> **(47)** PRC-024-2>> **(48)**	

(37) | Redline to Last Posted **(38)** **PRC-019-2** Clean **(39)** | Redline to Last Posted **(40)** **PRC-024-2** Clean **(41)** | Redline to Last Posted **(42)** SAR **(43)**				
White Paper Clean | Redline to Last Posted **Appendix A** – List of all NERC standards applicable to GOs/GOPs **Appendix B** – NERC standards recommended for consideration to clarify applicability for dispersed generation Unofficial Comment Form(Word)	Comment Period Info>> Submit Comments>> (Closed)	12/22/14 - 01/20/15	Comments Received>>	
Draft 1 PRC-005-5 Clean | Redline to Last Posted	Initial Ballot Info>> Vote>> (Closed)	1/12/15 – 1/22/15	Summary>> Ballot Results>>	Consideration of Comments>>

Implementation Plan **Supporting Documents** Unofficial Comment Form (Word) SAR	Comment Period Info>> Submit Comments>> (Closed)	12/8/14 – 1/22/15	Comments Received>>	
	Join Ballot Pool Info>> Join>> (Closed)	12/8/14 – 1/8/15		
Draft 1 Standards **PRC-001-1.1(X)** Clean **(6)** | Redline to PRC-001-1.1 **(7)** **PRC-019-2** Clean **(8)** | Redline to PRC-019-1 **(9)** **PRC-024-1(X)** Clean **(10)** | Redline to last posted PRC-024-1 **(11)** **Implementation Plans** PRC-001-1.1(X) **(12)** PRC-019-2 **(13)**	Initial Ballots Updated Info>> **(17)** Info>> **(18)** Vote>> (Closed)	12/10/14 – 12/23/14	Summary>> **(21)** Ballot Results PRC-001-1.1(X) **(22)** PRC-019-2 **(23)** PRC-024-1(X) **(24)**	Consideration of Comments>> Clean **(26)** | Redline **(27)**
	Comment Period Info>> **(19)** Submit Comments>> (Closed) The ballots and comment period have heen extended one additional day to 8 p.m. Eastern on Tuesday,	11/5/14 – 12/23/14	Comments Received>> **(25)**	

PRC-024-1(X) **(14)** **Supporting Documents** Unofficial Comment Form (Word) **(15)** SAR **(16)**	December 23, 2014 in order to reach quorum			
	Join Ballot Pools Info>>**(20)** Join>> (Closed)	11/5/14 – 12/4/14		
	The comment period and initial ballot close dates have been extended one day to December 22, 2014 (for the medium-priority Reliability Standards) due to a NERC.com maintenance outage that occurred on Saturday, December 13, 2014.			
Final Drafts **PRC-004-2.1(i)a** Clean | Redline to last posted Redline to PRC-004-2.1a **PRC-004-4** Clean | Redline to last posted Redline to PRC-004-3 **VAR-002-4** Clean | Redline to last posted Redline to VAR-002-3	Final Ballots Info>> Vote>> (Closed)	10/28/14 – 11/06/14	Summary>> Ballot Results PRC-004-2.1(i)a>> PRC-004-4>> VAR-002-4>>	

Implementation Plans **PRC-004-2.1(i)a** Clean (No changes to last posted) **PRC-004-4** Clean (No changes to last posted) **VAR-002-4** Clean (No changes to last posted) SAR				
Draft 2 Standard **PRC-004-2.1a(X)** Clean | Redline to PRC-004-2.1a Redline to last posted **PRC-004-4** Clean | Redline to PRC-004-3 Redline to last posted **Implementation Plans** PRC-004-2.1a(X) Clean | Redline to last posted PRC-004-4 Clean | Redline to last posted	Additional Ballots Updated Info>> Info>> Vote>> (Closed)	10/10/14 - 10/22/14	Summary>> Ballot Results PRC-004-2.1a(X)>> PRC-004-4>>	Consideration of Comments PRC-004>> VAR-002-4>>
	Comment Period Info>> Submit Comments>> (Closed)	9/5/14 - 10/22/14	Comments Received>>	

Supporting Documents Unofficial Comment Form (Word) Coordination Plan and Explanation of Version Numbers SAR				
Draft 2 **PRC-005-2(X)** Clean Redline to last posted Redline to PRC-005-2 **PRC-005-3(X)** Clean Redline to last posted Redline to PRC-005-3 **Implementation Plans** PRC-005-2(X) PRC-005-3(X) **Supporting Documents** Coordination Plan and Explanation of Version Numbers SAR	Final Ballots Info>> Vote>> (Closed)	8/27/14 – 9/5/14	Summary>> Ballot Results PRC-005-2(X)>> PRC-005-3(X)>>	
Draft 2 **VAR-002-2b(X)**	Additional Ballots Updated Info>>	10/7/14 – 10/16/14	Summary>>	

Clean Redline to Last Posted Redline to VAR-002-2b **VAR-002-4** Clean Redline to last posted Redline to VAR-002-3 **Implementation Plan** VAR-002-2b(X) VAR-002-4 **Supporting Documents** Unofficial Comment Form (Word) Coordination Plan and Explanation of Version Numbers SAR	Info>> Vote>> (Closed)		Ballot Results VAR-002-4>> VAR-002-2b(X)>>	
	Comment Period Info>> Submit Comments>> (Closed)	8/27/14 – 10/16/14	Comments Received>>	
Draft 1 Standard **PRC-004-2.1a(X)** Clean | Redline to PRC-004-2.1a **PRC-004-3(X)** Clean | Redline to PRC-004-3 **Implementation Plans** PRC-004-2.1a(X)	Initial Ballots Updated Info>> Info>> Vote>> (Closed)	8/15/14 – 8/26/14	Summary>> Ballot Results PRC-004-2.1a(X)>> PRC-004-3(X)>>	
	Comment Period Info>>	7/10/14 – 8/26/14	Comments Received>>	Consideration of Comments>>

PRC-004-3(X) **Supporting Documents** Unofficial Comment Form (Word) Coordination Plan and Explanation of Version Numbers SAR **Draft Reliability Standard Audit Worksheets (RSAW)** PRC-004-2.1a PRC-004-3 PRC-005-1.1b	Submit Comments>> (Closed)			
	Join Ballot Pools>> (Closed) Please note: As a convenience to stakeholders, if you have previously joined the ballot pool for VAR-002-2b(X), no action is needed - you have automatically been entered into both the PRC-004-2.1a(X) and PRC-004-3(X) ballot pools. If you have been automatically entered and do not wish to participate, please contact Wendy Muller **prior to July 16, 2014** to have your name removed.	7/10/14 - 7/16/14		
Draft 1 Standards **PRC-005-2(X)** Clean | Redline to PRC-005-2 **PRC-005-3(X)** Clean | Redline to PRC-005-3 **PRC-005-X(X)** Clean | Redline to last posted PRC-005-X **VAR-002-2b(X)** Clean | Redline to VAR-002-2b	Initial Ballots Updated Info>> Info>> Vote>> (Closed)	7/18/14 – 7/29/14	Summary>> Ballot Results: PRC-005-2(X)>> PRC-005-3(X)>> PRC-005-X(X)>> VAR-002-2b(X)>> VAR-002-4>>	

VAR-002-4 Clean | Redline to VAR-002-3 **Implementation Plans** PRC-005-2(X) PRC-005-3(X) PRC-005-X(X) VAR-002-2b(X) VAR-002-4 **Supporting Documents** Unofficial Comment Form (Word) Coordination Plan and Explanation of Version Numbers SAR **Draft Reliability Standard Audit Worksheets (RSAW)** VAR-002-2b VAR-002-3	Formal Comment Period Info>> Submit Comments>> (Closed)	6/12/14 – 7/29/14	Comments Received>>	Consideration of Comments>>
	Join Ballot Pool Info>> Join>> (Closed) Please note: these ballot pool join periods have been extended to 8 p.m. Eastern on Wednesday, July 16, 2014 in order to keep the closing dates for Project 2014-01 the same.	6/12/14 – 7/16/14		
White Paper **Appendix A** – List of all NERC standards applicable to GOs/GOPs	Informal Comment Period Info>> Submit Comments>>	04/17/14 - 05/05/14	Comments Received>>	Consideration of Comments>>

Appendix B – NERC standards recommended for consideration to clarify applicability for dispersed generation Unofficial Comment Form				
SAR **(1)** **Supporting Documents:** Unofficial Comment Form (Word) **(2)**	Comment Period Info>> **(3)** Submit Comments>>	11/20/13 - 12/19/13 (closed)	Comments Received>> **(4)**	Consideration of Comments>> **(5)**

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Authorization Request Form

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

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

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Application of certain GO/GOP Reliability Standards and Requirements to Dispersed Generation		
Date Submitted:	10/1/2013		
SAR Requester Information			
Name:	Jennifer Sterling-Exelon, Gary Kruempel-MidAmerican, Allen Schriver-NextEra Energy, Inc., Brian Evans-Mongeon-Utility Services Inc.		
Organization:	Exelon, MidAmerican, NextEra Energy, Utility Services Inc.		
Telephone:	(630) 437-2764 – primary contact	E-mail:	jennifer.sterling@exeloncorp.com primary contact
SAR Type (Check as many as applicable)			
☐ New Standard ☒ Revision to existing Standard		☐ Withdrawal of existing Standard ☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
The industry is requesting that the application section of certain GO/GOP Reliability Standards or the requirements of certain GO/GOP Reliability Standards be revised in order to ensure that the Reliability Standards are not imposing requirements on dispersed generation that are unnecessary and/or counterproductive to the reliable operation of the Bulk Electric System (BES). For purposes of this SAR, dispersed generation are those resources that aggregate to a total capacity greater than 75 MVA (gross

SAR Information
nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. This request is related to the proposed new definition of the Bulk Electric System (BES) from Project 2010-17, that results in the identification of elements of new dispersed generation facilities that if included under certain Reliability Standards may result in a detriment to reliability or be technically unsound and not useful to the support of the reliable operation of the BES .
Purpose or Goal (How does this request propose to address the problem described above?):
The goal of the request is to revise the applicability of GO/GOP Reliability Standards or the Requirement(s) of GO/GOP Reliability Standards to recognize the unique technical and reliability aspects of dispersed generation, given the proposed new definition of the BES.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objective of the revisions to the applicability section and/or Requirements of certain GO/GOP Reliability Standards is to ensure that these revisions are approved by the Board of Trustees and applicable regulatory agencies prior to the effective date for newly identified elements under the proposed BES definition (i.e., June 2016).
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The scope of this SAR involves revisions to the applicability section of the following GO/GOP Reliability Standard applicability sections and/or Reliability Standard Requirements: (a) PRC-005-2 (-3); (b) FAC-008-3; (c) PRC-023-3/PRC-025-1; (d) PRC-004-2a (-3) ; and (e) VAR-002-2 so it is clear what, if any, requirements should apply to dispersed generation. Also, IRO,MOD, PRC or TOP Standards that require outage and protection and control coordination, planning, next day study or real time data or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities and reporting are conducted at the point of aggregation to 75 MVA, and not at an individual turbine, inverter or unit level for dispersed generation. This scope would also include development of a technical guidance paper for standard drafting teams developing new or revised Standards, so that they do not incorrectly apply requirements to dispersed generation unless such an application is technically sound and promotes the reliable operation of the BES. To the extent, there are existing Reliability Standard Drafting Teams that have the expertise and can make the requested changes prior to the compliance date of newly identified assets under the BES definition (i.e., June 2016), those projects may be assigned the required changes as opposed to creating new projects.

SAR Information
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

The following description and technical justification(including an assessment of reliability impacts) is provided for the standard drafting teams to execute the SAR for each applicable Standard.

PRC-005-2

Testing and maintenance of protection and control equipment for dispersed generation should start at the point of aggregation to 75 MVA. Manufacturers of dispersed generation turbines and solar panels recommend against specific testing and maintenance regimes for protection and control equipment at the dispersed generation turbine and panel level. In fact it is counterproductive to implement protection and control at the individual turbine, solar panel, or unit level. Instead this is best done at an aggregated level. Therefore, PRC-005 should indicate that the standard applies at the point of aggregation to at 75 MVA or greater for dispersed generation. This change would clarify that the facility section 4.2.5.3 is the section that would apply to dispersed generating facilities and that the remaining sections would not apply.

FAC-008-3

For dispersed generation, it is unclear if in FAC-008-3 the term “main step up transformer” refers to the padmount transformer at the base of the windmill tower or to the main aggregating transformer that steps up voltage to transmission system voltage. From a technical standpoint, it should be the point of aggregation at 75 MVA or above that is subject to this standard for dispersed generation, such as wind. It is at the point of aggregation at 75 MVA or above that facilities ratings should start, since it is this injection point at which a planner or operator of the system is relying on the amount of megawatts the dispersed generation is providing with consideration of the most limiting element. To require facility ratings at for each dispersed turbine, panel or generating unit is not useful to a planner or operator of the system, and, therefore, FAC-008-3 should be revised to be clear that facility ratings start at the point of aggregation at 75 MVA or above for dispersed generation.

SAR Information

Also consider that the BES definition specifically excludes collector system equipment at less than 75 MVA from being included in the BES. Thus, those portions of the collector systems that handle less than 75 MVA are not BES "Facilities," and, therefore, need not be evaluated per R1 or R2. Given this, there seems to be no technical value to conduct facility ratings for individual dispersed generation turbines, generating units and panels.

PRC-023-3/PRC-025-1

In keeping with the registration criteria for Generator Owners as well as the proposed BES Definition, the 75MVA point of aggregation should be the starting point for application of relay loadability requirements.

PRC-004-2

There is no technical basis to claim that misoperation analysis, corrective action plan implementation and reporting for dispersed generation at the turbine, generating unit or panel level is needed for the reliable operation of the BES. Similar to the statements above, the appropriate point to require misoperation analysis, corrective action plan implementation and reporting is at the point of aggregation at 75 MVA and above.

VAR-002-2

Voltage control for some types of dispersed generating facilities is accomplished by a controller that is able to adjust either generating unit controls or discrete reactive components to provide transmission system voltage adjustment. The VAR-002 standard should be modified to allow this type of control for dispersed generation facilities under the requirements of the standard.

General review of IROs, MODs, PRCs, TOPs

IRO, MOD, PRC or TOP Standards that require outage and protection and control coordination, planning, next day study or real time data or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities are conducted at the point of aggregation at 75 MVA, and not an individual turbine, generating unit or panel level for dispersed generation. Unless this clarity is provided applicability at a finer level of granularity related to dispersed generation may be seen as required and such granularity will result in activities that have no benefit to

SAR Information
reliable operation of the BES. Furthermore applicability at a finer level of granularity will result in uneeded and ineffective collection, analysis, and reporting activities that may result in a detriment to reliability.

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

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

Reliability and Market Interface Principles		
Applicable Reliability Principles (Check all that apply).		
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.	
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.	
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.	
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.	
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.	
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.	
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.	
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.	
Does the proposed Standard comply with all of the following Market Interface Principles?		Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.		Yes

Reliability and Market Interface Principles	
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
PRC-005-2, FAC-008-3, PRC-023-3/PRC-025-1/PRC-004-2a, VAR-002-2b and various IRO, MOD, PRC and TOP Standards	See explanation under technical analysis.

Related SARs	
SAR ID	Explanation
	N/A

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Standard Authorization Request - Application of Certain GO/GOP Reliability Standards and Requirements to Dispersed Generation

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the definition. The electronic comment form must be completed by **December 19, 2013**.

All documents and information about this project are available on the project page. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Background Information

The Standards Authorization Request (SAR) asks that the applicability section of certain Reliability Standards that apply to a Generator Owner (GO)/Generator Operator (GOP) or the requirements of certain GO/GOP Reliability Standards be reviewed, and where appropriate revised to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk Electric System (BES). Dispersed generation resources are those resources that are small-scale power generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include but are not limited to solar, geothermal, energy storage, flywheels, wind, micro-turbines, and fuel cells.

This request is related to the revised definition of the Bulk Electric System (BES) from Project 2010-17, and it is desirable to complete any revisions determined to be necessary so that revisions are approved by the Board of Trustees and applicable regulatory agencies prior to the effective date for newly identified elements under the revised BES definition. This effective date is expected to be July 1 2016, although it is possible that regulatory action could change the date.

The scope of the SAR involves review of and possible revisions to the applicability section of the following Reliability Standard applicability sections and/or Reliability Standard requirements applicable to GOs/GOPs: (a) PRC-005-2 (-3); (b) FAC-008-3; (c) PRC-023-3/PRC-025-1; (d) PRC-004-2a (-3) ; and (e) VAR-002-2 so it is clear what, if any, requirements should apply to dispersed generation. Also, any IRO, MOD, PRC, or TOP standards that require outage and protection and control coordination, planning, next day study or real time data, or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities and reporting are conducted at the point of aggregation to 75 MVA, and not at an individual turbine, inverter, or unit level for dispersed generation.

The scope of work would also include development of a technical guidance paper for Standard Drafting Teams developing new or revised standards, so that they do not incorrectly apply requirements to dispersed generation unless such an application is technically sound and promotes the reliable operation of the BES.

To the extent there are existing Standard Drafting Teams that have the expertise and can make the requested changes prior to the compliance date of newly identified assets under the BES definition (i.e., June 2016), those projects may be assigned the required changes as opposed to creating new projects.

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Questions

1. Do you agree with the scope and objectives of this SAR? If not, please explain why you do not agree and, if possible, provide specific language revisions that would make it acceptable to you.

   Yes:

   No:

   Comments:

2. Do you agree that the scope of the SAR should be limited to considering revisions necessary to address the unique technical and reliability aspects of dispersed generation resources, or should the scope encompass consideration of changes to standards applicability for all small generation regardless of type? Please provide a technical rationale for your response.

   Yes:

   No:

   Comments:

3. Do you agree with the list of standards to be reviewed? If you do not agree, please note specific standards you think should be added to or removed from the list.

   Yes:

   No:

   Comments:

4. Are you aware of any business practice that will be needed or that will need to be modified as a result of this SAR should it move forward? If yes, please identify the business practice.

   Yes:

   No:

   Comments:

5. Are you aware of any Canadian provincial or other regulatory requirements that may need to be considered during this project in order to develop a continent-wide approach to the standard(s)? If yes, please identify the jurisdiction and specific regulatory requirements.

   Yes:

   No:

   Comments:

6. Are there any other concerns with this SAR that haven't been covered in previous questions?

   Yes:

   No:

   Comments:

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Standards Announcement

Project 2014-01 Standards Applicability for Dispersed Generation Resources

SAR Formal Comment Period: November 20, 2013 – December 19, 2013

Now Available

A 30-day formal comment period for the Project 2014-01 Standards Applicability for Dispersed Generation Resources Standard Authorization Request (SAR) is now open through **8 p.m. Eastern on Thursday, December 19, 2013.**

Background information for this project can be found on the project page.

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Thursday, December 19, 2013.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller, Standards Development Administrator, or at 404-446-2560.

North American Electric Reliability Corporation
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Individual or group. (28 Responses)
Name (17 Responses)
Organization (17 Responses)
Group Name (11 Responses)
Lead Contact (11 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (1 Responses)
Comments (28 Responses)
Question 1 (27 Responses)
Question 1 Comments (27 Responses)
Question 2 (24 Responses)
Question 2 Comments (27 Responses)
Question 3 (0 Responses)
Question 3 Comments (27 Responses)
Question 4 (0 Responses)
Question 4 Comments (27 Responses)
Question 5 (0 Responses)
Question 5 Comments (27 Responses)
Question 6 (0 Responses)
Question 6 Comments (27 Responses)

Group
Caithness Shepherds Flat, LLC
Jeffrey Delgado
Yes
Yes
Caithness Shepherds Flat Wind Farm (CSF), located in Oregon, supports the SAR as written and believes the scope should address dispersed generation resources with collector systems only. In the development of CSF's NERC compliance program, it became apparent that some GO/GOP applicable Reliability Standards were written with fossil fuel facilities in mind, and not generation resources such as wind. The VAR-002 standard for example, requiring reactive and voltage control of individual generators and notification of the TOP when there is a change in status, would appear to be irrelevant to the TOP, but rather the aggregate MW output at the point of interconnection should be what is relevant. CSF's wind farm consists of several hundred wind turbines, all < 3 MW in nameplate capacity. The TOP does not need to be notified about individual turbine voltage status, as any loss of voltage control of an individual turbine will not be detected by the TOP. The relevant factor is in the voltage at the point of interconnection which is controlled by a "Wind Farm Management System" WFMS voltage control system. Change in status of the WFMS would be of interest to the TOP, so the standard should allow for this variance.
Yes
No
No
No
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
Yes
No

Scope should expanded to include all small generators regardless of types. There is no specific reason to not include all. Generally, there is little reliability benefits to BES by applying NERC standards to small generators regardless of the type.
Yes
No
No
No
Group
SPP Standards Review Group
Robert Rhodes
Yes
No
We believe that this evaluation should be extended to all small generation regardless of type because the impact on the BES would be the same regardless of the source or prime mover of the generation.
While we may agree with the list of standards as presented in the SAR we would encourage the SAR drafting team to not limit itself to just those particular standards. For example, once a drafting team is established and work begins on the project, we don't want the project to be limited by the scope as currently defined in the SAR. We need to factor in some flexibility to go beyond this specific list to capture all those standards/requirements/definitions which may be impacted in this review.
Not at this time.
Although we are not aware of any specific federal regulatory requirements, the drafting team needs to keep in mind that there may be state regulatory requirements established for dispersed generation that may need to be considered in this project.
Regarding the July 2016 deadline, the drafting team needs to be sure that this effort is complete in time for the industry to be ready by July 2016. We need to be sure that as the deadline approaches, compliance preparations aren't made and then un-made as a result of a modification to an existing standard which is impacted by this effort. In the 1st line of the 1st paragraph of the Industry Need section under SAR Information, we suggest replacing 'application' with 'applicability'. In the 5th line of the 1st paragraph of the Brief Description section under SAR Information, replace 'real time' with 'Real-time', the NERC Glossary term. In the 1st line of the FAC-008-3 paragraph under SAR Information, hyphenate step-up. In the next to last line of the General review of IROs, MODs, PRCs, TOPs paragraph, change 'uneeded' to 'unneeded'.
Group
Northeast Power Coordinating Council
Guy Zito
Yes
Yes.
No.
Yes. It must be considered that the operating system in Quebec follows chapter R-6.01 An Act Respecting the Regie de L'Energie, which details: (1) an owner or operator of a facility with a capacity of 44 kV or more connected to an electric power transmission system; (2) an owner or operator of an electric power transmission system; (3) an owner or operator of a production facility with a capacity of 50 megavolt amperes (MVA) or more connected to an electric power transmission system; (4) a distributor with a peak capacity of over 25 megawatts (MW), whose facilities are connected to an electric power transmission system; and (5) a person who uses an electric power transmission system under an electric power transmission service agreement with the electric power carrier or with any other carrier in Québec.

No.
Individual
Thomas Foltz
American Electric Power
Yes
AEP would prefer that the solution for applicability of dispersed generation at the turbine or generating unit level would be by adjusting the BES definition accordingly. Creating a new SAR, allowing this topic be discussed within the framework of the BES definition itself, would seem the most direct and efficient way of debating the topic. However, if that cannot be accomplished, AEP supports the effort of this SAR as an alternative (though less desirable) means to accomplish the same goal.
No
We believe it is preferable, at least initially, for the scope to remain limited to dispersed generation resources.
Every standard that involves the GO and/or GOP should be included in the scope of the SAR. This does not imply that all standards should be modified, but the SDT and commenters should be afforded the opportunity to consider the impacts of such changes. For example, PRC-024, PRC-001, CIP-002 through CIP-011, etc. should be considered.
No.
No.
No.
Individual
Shirley Mayadewi
Manitoba Hydro
Yes
Yes
No
No
Although we do not have any concerns with this SAR, we have the following suggestions to improve clarity. (1) Industry Need - remove the words “Bulk Electric System” from the second paragraph to leave only the acronym, BES because this is the second instance of BES in the document. (2) SAR Information - capitalize ‘misoperation’ because it appears in the Glossary of Terms.
Individual
Patricia Metro
National Rural Electric Cooperative Association
No
NRECA does not believe this SAR is necessary. If entities with dispersed generation are registered as a Generator Owner (GO)/Generator Operator (GOP), it is the obligation of the registered entity to determine applicable standards and associated requirements and be able to explain how it complies accordingly. There is no need to modify the applicability of standards to specifically recognize dispersed generation as there is no recognizable reliability gap with the existing applicability of the standards included in this SAR.
No
See response to Question 1
See response to Question 1

Individual
David Jendras
Ameren
Yes
(1) The proposed SAR appears to advocate the GSU as the Element within these standards' applicability, which appears reasonable for a SAR. However, we believe that this conflicts with the BES Definition Phase 2 Reference figures. Our expectation is that the BES Definition would be included in the scope of this SAR.
Yes
Yes, we agree.
(1) Apply the Generator Site Boundary used in the BES Definition Reference (e.g. Figure I2-5) consistently for dispersed generation so that multiple GSU do not circumvent the 75MVA aggregate. (2) Develop a NERC Glossary definition for the term 'dispersed generation'.
Individual
Silvia Parada Mitchell
NextEra Energy
Agree
MidAmerican
Individual
Jonathan Meyer
Idaho Power
No
The BES definition in process has addressed the concerns raised in the SAR (in our opinion). Application of Standards applies to BES elements unless specifically excluded.
No
I see no need for a SAR.
No
N/A
N/A
Individual
Alice Ireland
Xcel Energy
Yes
We strongly support the objective of this SAR.
We believe that in addition to the approved standards mentioned in the SAR, NERC should communicate this issue directly to drafting teams working on active projects such as PRC-004-3 or PRC-027-1 to assure that they consider the applicability of their standard relative to dispersed generation and, if it is intended to include dispersed generation as in scope, to assure that correct terminology is used within their draft standard to avoid ambiguity and inconsistencies such as the SAR discusses for use of the term "main step up transformer" in FAC-008-3.

Individual
John Seelke
Public Service Enterprise Group
No
The SAR relies upon the phase 2 BES definition, as recently approved by the ballot body, but which has yet to be approved by the NERC Board or FERC. Under this definition, traditional generators at a site that exceed 75 MVA in aggregate as well as the all the equipment from terminals of each generator to the connection point with the BES are included in BES. Dispersed generators are treated differently. The individual dispersed generators are part of the BES if they are at a site where their aggregate nameplate capacity exceeds 75 MVA and they are connected to the BES; however, only equipment that delivers capacity from the point where those resources aggregate to greater than 75 MVA are included in the BES. Stated differently, traditional generators are contiguous with the BES, from the individual BES generators to their connection to the BES. Dispersed generators are not contiguous with the BES – the equipment that aggregate their output prior to it exceeding 75 MVA is excluded. These exclusions create a gap between dispersed BES generators and the BES they connect to. All generators should be treated comparably. The Eastern Interconnection Reliability Assessment Group (ERAG) manual supports our recommendation regarding inclusion equipment for dispersed generators. Wind farm modeling, as specified in the ERAG manual, (https://rfirst.org/reliability/easterninterconnectionreliabilityassessmentgroup/mmwg/Documents/MMWG%20Procedure%20Manual%20V10.pdf) requires a high level of detail – see p. 30, item 6, which states: “Wind Farms - Include all 34.5 kV collector bus(es) and the main facility step-up transformer(s) from 34.5 kV to transmission voltage, as well as one 0.600 kV (or whatever the wind generator nominal voltage is) level bus off each collector bus with a lumped generator and lumped GSU representing the aggregate of the wind turbines attached to that collector bus and their GSUs.” Thus, the ERAG manual requires modeling of non-BES Elements under phase 2 BES definition – see the BES Webinar slides nos. 5-7. (http://www.nerc.com/pa/Stand/WebinarLibrary/bes_phase2_third_posting_20131010_webinar_final.pdf) Setting aside our phase 2 definition concerns, the SAR does not make a coherent technical case for any standards changes. As an example, the justification for a change in PRC-005-2 has contradicting statements: “Manufacturers of dispersed generation turbines and solar panels recommend against specific testing and maintenance regimes for protection and control equipment at the dispersed generation turbine and panel level. In fact it is counterproductive to implement protection and control at the individual turbine, solar panel, or unit level. Instead this is best done at an aggregated level.” In the first sentence, it appears that manufacturers install protection and control equipment at the “dispersed generation turbine and panel level,” yet the next sentence states that “it is counterproductive to implement protection and control at the individual turbine, solar panel, or unit level.” Which is it? During the balloting of PRC-005-2, no comments were submitted to the drafting team regarding the changes proposed in the SAR for PRC-005-2. Yet only a year after the final ballot on PRC-005-2, the SAR proposes changes to PRC-005-2 (and other standards) because the phase 2 definition, according to the SAR, would result in BES equipment at “dispersed generation facilities that if included under certain Reliability Standards may result in a detriment to reliability or be technically unsound and not useful to the support of the reliable operation of the BES.” We believe that dispersed generators will have less equipment, not more, under the proposed BES definition because of the excluded equipment under that definition. Finally, there has been no justification put forth that would justify different treatment of dispersed generation from traditional generation. See our remarks in questions 2 and 6 below.
No
As stated previously, “small generators” (traditional versus dispersed) are not treated comparably in the phase 2 definition – traditional BES generators must be contiguous with the BES but dispersed generators need not be. While we would welcome changes that provide for comparable treatment for small generators, regardless of type, the unequal treatment embedded in the phase 2 definition must be corrected before those changes are considered.

No comments
No comments
No comments
Section 303 of the NERC ROP addresses “Relationship between Reliability Standards and Competition.” Item 1 states: “Competition — A Reliability Standard shall not give any market participant an unfair competitive advantage.” By not treating all generators comparably, the SAR violates item 1. Based upon this and our prior comments, we recommend that the SAR be rejected by the Standards Committee.
Individual
Barbara Kedrowski
Wisconsin Electric Power Company
No
The SAR needs to include applicability to CIP-002-5, proposed for the identification of BES Cyber Assets and BES Cyber Systems. If individual wind turbines are included in the BES, those cyber assets which support their operation (monitoring and control functions local to each turbine) would become BES Cyber Systems subject to some level of compliance requirements of the CIP v5 standards. The SAR needs to include all the CIP version 5 standards, including CIP-010 and CIP-011. Addtionally, these standards need to be listed: PRC-001/027 – Coordination for distributed resources needs to be accomplished with the collector system of the distributed resource, not with the transmission system. The collector system needs to be coordinated with the transmission system, however, the BES definition specifically excludes collector system equipment at less than 75 MVA from being included in the BES. PRC-024 – In most cases most distributed resources are many identical units. It would seem reasonable to document the relay data for one unit and then use it for many. PRC-019 – Voltage control for some types of dispersed generating facilities is accomplished by a controller that is able to adjust either generating unit controls or discrete reactive components to provide transmission system voltage adjustment. The PRC-019 standard should be modified to allow coordination with this type of control for dispersed generation facilities under the requirements of the standard. MOD 012/032 – In most cases most distributed resources are many identical units. It would seem reasonable to provide an example model of one resource and then use it for many. MOD 025 & 026 and 027 – In most cases most distributed resources are many identical units. It would seem reasonable to validate one unit and then use the results for many.
Response from Q1: The SAR needs to include applicability to CIP-002-5, proposed for the identification of BES Cyber Assets and BES Cyber Systems. If individual wind turbines are included in the BES, those cyber assets which support their operation (monitoring and control functions local to each turbine) would become BES Cyber Systems subject to some level of compliance requirements of the CIP v5 standards. The SAR needs to include all the CIP version 5 standards, including CIP-010 and CIP-011. Addtionally, these standards need to be listed: PRC-001/027 – Coordination for distributed resources needs to be accomplished with the collector system of the distributed resource, not with the transmission system. The collector system needs to be coordinated with the transmission system, however, the BES definition specifically excludes collector system equipment at less than 75 MVA from being included in the BES. PRC-024 – In most cases most distributed resources are many identical units. It would seem reasonable to document the relay data for one unit and then use it for many. PRC-019 – Voltage control for some types of dispersed generating facilities is accomplished by a controller that is able to adjust either generating unit controls or discrete reactive components to provide transmission system voltage adjustment. The PRC-019 standard should be modified to allow coordination with this type of control for dispersed generation facilities under the requirements of the standard. MOD 012/032 – In most cases most distributed resources are many identical units. It would seem reasonable to provide an example model of one resource and then use it for many. MOD 025 & 026 and 027 – In most cases most distributed resources are many identical units. It would seem reasonable to validate one unit and then use the results for many.

Group
MRO NERC Standards Review Forum
Russel Mountjoy
Yes
The SAR indicates several standards that should be considered for modification for dispersed generating units. It also provides for examination of other standards that may need to be similarly modified to accommodate the unique aspects of dispersed generation. In addition the SAR provides an explanation of which types of generation are to be reviewed in this project and this explanation is appropriate to define the scope of the project.
Yes
The SAR does not specify what types of generation should be included for analysis as “dispersed generation resources. It only refers to those that are a part of a facility that aggregates to 75 MVA or more. As written the SAR is not limited to any particular type of small generation. Under the SAR all types could and should be considered for revision.
The SAR provides a list of several specific standards application to Generator Owners and/or Generator Operators that would be reviewed as part of the project. In addition it proposes a review of several project families (IRO,MOD, PRC and TOP) that would be examined. The specific list is recommended as proposed in the SAR and with the flexibility to review other standards the list as indicated is appropriate Consideration should be given to an addition to the Attachment in CIP-002 to add an item that would exclude components below the 75MVA aggregation point. The reasoning would be parallel to the other standards addressed in the SAR where the aggregation point would be identified as the point at which the standard would apply. For CIP the result would be that the components below the aggregation point would not have to be addressed, i.e. they would not be high, medium, or low.
The SAR includes the objective to complete the changes and obtain regulatory approval prior to the completion of the implementation of the BES definition. It is essential that this schedule is met so that dispersed generation owners and operators can plan and implement their compliance programs without having to temporarily implement requirements that will be superseded by this project.
Individual
Chris Scanlon
Exelon
Yes
The SAR indicates several standards that should be considered for modification for dispersed generating units. It also provides for examination of other standards that may need to be similarly modified to accommodate the unique aspects of dispersed generation. In addition the SAR provides an explanation of which types of generation are to be reviewed in this project and this explanation is appropriate to define the scope of the project.
Yes
Yes, the SAR should focus on generation resources that are part of a facility that aggregates dispersed resources at 75 MVA or more. We believe the intent is to exclude individual units from certain requirements when those units do not meet the reporting criteria but are part of a facility that aggregates those units at the BES voltage level. We note that the question may lead to confusion. As written the use of "or" appears to be implying there is a choice between "dispersed generation" as used in the first clause of the question and some generation "types" (undefined but commonly understood to refer to fuel source) as used in the second clause. We do not believe the SAR should exclude generation based on fuel type.
The SAR provides a list of several specific standards application to Generator Owners and/or Generator Operators that would be reviewed as part of the project. In addition it proposes a review of several project families (IRO,MOD, PRC and TOP) that would be examined. The specific list is

recommended as proposed in the SAR and with the flexibility to review other standards the list as indicated is appropriate.
No
No
The SAR includes the objective to complete the changes and obtain regulatory approval prior to the completion of the implementation of the BES definition. It is essential that this schedule is met so that dispersed generation owners and operators can plan and implement their compliance programs without having to temporarily implement requirements that will be superseded by this project.
Individual
David Greyerbiehl
Consumers Energy Company
Yes
Yes
Yes
The SAR is required at a minimum, but a change to the BES definition is more appropriate. From the comments below submitted during the BES, the BES definition should at minimum be modified to provide consistency between generating resources (I2) and dispersed power producing resources (I4). Generating resources are required to be 20MVA in order to be considered an BES element, while dispersed power producing resources have no size consideration as long as they meet the net total MVA. Consumers Energy has completed studies with an operating wind farms and the loss of individual resources makes no impact the BES. The addition of individual resources does not make improve reliability as they have no effect on the system. The SAR intention is to modify the individual standards to define the requirements for all the additional BES elements that are being added that are not presently addressed in the standards or are against the manufacturers recommendations. While this approach can be used, and is required if the BES definition is not changed. A better method would be to include dispersed power producing resources at a point in which the total affects the BES and not as individual units. Previous Comments on BES definition: The inclusion and the clarification of the inclusion seem to contradict each other. The highlight portion above seems to indicate inclusion only from the point of aggregation of 75MVA or above. This, in most Wind Park cases would include a collector bus but probably not individual wind turbines. However I4 seems to indicate that the case of a Wind Park that has a total aggregation of 75 MVA, all associated equipment including every individual wild turbine would be included. There is inconsistency. If and when Distributed Generation gains saturation is it our intent that whole neighborhoods or industrial parks be considered BES resources? Technical justification should be needed to include resources in the BES, not the other way around. Is there a real expectation that a single collector circuit containing ten, 1.2MW wind turbines can cause cascading or uncontrollable outages of the surrounding system? It is extremely doubtful. We can support the inclusion of equipment where the aggregation of 75 MVA or more connects to the Bulk Electric System at voltages of 100kv or greater. There is a clear indication here that a single contingency can remove the total of the capacity from the system where with this definition as proposed, that is simply not the case.
No
No
Group
ISO/RTO Council Standards Review Committee
Greg Campoli
Yes
Yes

Small generators that do not meet the individual 20 MVA criteria and are not part of the aggregated 75 MVA group that meets the BES inclusion criteria are not regarded BES facilities and therefore do not need to be addressed by this SAR. The scope therefore does not need to be expanded to all small generators.
Yes
No
No
No
Individual
Gary Kruempel
MidAmerican Energy Company
These comments were developed by NextERA (contact Brian Murhpy), MidAmerican, and Exelon
Yes
The SAR indicates several standards that should be considered for modification for dispersed generating units. It also provides for examination of other standards that may need to be similarly modified to accommodate the unique aspects of dispersed generation. In addition the SAR provides an explanation of which types of generation are to be reviewed in this project and this explanation is appropriate to define the scope of the project.
Yes
The SAR does not specify what types of generation should be included for analysis as “dispersed generation resources. It only refers to those that are a part of a facility that aggregates to 75 MVA or more. As written the SAR is not limited to any particular type of small generation. Under the SAR all types could and should be considered for revision.
The SAR provides a list of several specific standards application to Generator Owners and/or Generator Operators that would be reviewed as part of the project. In addition it proposes a review of several project families (IRO,MOD, PRC and TOP) that would be examined. The specific list is recommended as proposed in the SAR and with the flexibility to review other standards the list as indicated is appropriate Consideration should be given to an addition to the Attachment in CIP-002 to add an item that would exclude components below the 75MVA aggregation point. The reasoning would be parallel to the other standards addressed in the SAR where the aggregation point would be identified as the point at which the standard would apply. For CIP the result would be that the components below the aggregation point would not have to be addressed, i.e. they would not be high, medium, or low.
No
No
The SAR includes the objective to complete the changes and obtain regulatory approval prior to the completion of the implementation of the BES definition. It is essential that this schedule is met so that dispersed generation owners and operators can plan and implement their compliance programs without having to temporarily implement requirements that will be superseded by this project.
Individual
Bill Fowler
City of Tallahassee (TAL)
Yes
Should the 75MVA be differentiated for Solar PV and other generating units that have both a DC and AC rating?
Yes
Dispersed generation should include intermittent power sources such as wind and solar, but also non-intermittent such as WTE, biogas and biomass generation sources.
yes
No. The City of Tallahassee is not aware of other business practices to be included.
No. The City of Tallahassee is not aware of such.

No.
Group
ACES Standards Collaborators
Ben Engelby
Yes
We find this SAR timely and necessary to avoid confusion in the application of the revised definition of the Bulk Electric System.
No
No, we do not agree that the scope of the SAR should be limited. The scope of the SAR should be to review standards applicable to GO/GOP and to limit the applicability based on the revised definition of the BES. Small generation regardless of type should be included in this review.
We agree with the list of standards to be reviewed. We would like to see flexibility in the scope of standards to be reviewed in the event that another standard is added during the standards development phase.
No.
No.
No other concerns.
Group
Duke Energy
Michael Lowman
Yes
Yes
(1) Duke Energy agrees that the scope of the SAR should be limited to Disperse Generation only.
(1) PRC-004-WECC-1 should also be included in this SAR with the same justification provided for the NERC Standard PRC-004-2
(1) Duke Energy is concerned that Dispersed Generation will have to be compliant with the BES definition Phase 1 prior to the Implementation of this Project and the implementation of Phase 2 of the BES definition. (2) Financial implications to registered entities should be considered and included in the Industry Need section of the SAR such as additional human resources required to maintain compliance if the standards are not revised for the applicability of dispersed generation resources at the point of aggregation to 75 MVA or greater.
Group
DTE Electric
Kathleen Black
Yes
Yes
Yes As stated in the background information, any relevant standard should be revised as necessary to insure that it is being applied at the point of aggregation.
No
No
No
Individual

Scott Langston
City of Tallahassee
Yes
Should the 75MVA be differentiated for Solar PV and other generating units that have both a DC and AC rating?
Yes
Dispersed generation should include intermittent power sources such as wind and solar, but also non-intermittent such as WTE, biogas and biomass generation sources.
Yes
No
No
No
Individual
Carla L. Holly
BP Wind Energy North America Inc.
Yes
Yes
The scope of the SAR should be limited to considering revisions necessary to address the unique technical and reliability aspects of dispersed generation resources as dispersed generation resources are unique and have operational characteristics that are not similar to most conventional generators, including generators that are considered to be classified as small.
Yes. We agree with the list of standards to be reviewed; however, we suggest more clarification about which specific IRO, MOD, PRC, and TOP standards would be considered as the SAR currently lists these categories generically.
No.
No.
No.
Individual
Karen Webb
City of Tallahassee
Yes
Should the 75MVA be differentiated for Solar PV and other generating units that have both a DC and AC rating?
Yes
Dispersed generation should include intermittent power sources such as wind and solar, but also non-intermittent such as waste-to-energy, biogas, and biomass generation sources.
Group
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Wayne Johnson

Yes
No
We believe the scope should include consideration of changes to standards applicability for all small generation. In particular, individual generators < 75 MVA should be exempted from model validation requirements unless transmission planning studies demonstrate such individual generators are critical to BES reliability. This would significantly reduce the compliance burdens being imposed on many GOs and GOPs and improve the focus on generators that are critical to reliability.
No. Need to also add those included in the Generator Verification Standard suite, including PRC-019, PRC-024, MOD-025, MOD-026, MOD-027. We are concerned with how certain standard requirements such as VAR-002 R3 can be applied to facilities with multiple “mini” units operating in parallel. For example, in the case of small turbine-generators one or more units operating in manual regulator mode would not have the same impact to the BES as a single large unit. Similar issues exist when some of the other listed standard requirements are applied such as model validation of excitation systems and governors (MOD-026 & MOD-027, as noted above).
No
No
No
Individual
Peter A. Heidrich
Florida Reliability Coordinating Council, Inc.
No
The SAR should not be limited to dispersed power producing resources only. A significant issue that will prove to derail this project is the potential inequitable treatment of generation. The scope should include all small generators regardless of fuel source or prime mover force. The scope should further identify small package style units that are typically considered 'run to fail' units. Provisions with in the 'Applicability' of the appropriate Reliability Standards that take into account these types of units would significantly reduce the compliance obligations for units that simply are replaced (in whole)when a failure occurs.
No
The scope should include all small generators regardless of fuel source or prime mover force. The scope should further identify small package style units that are typically considered 'run to fail' units. The reliability benefit of a generating facility is based on the MVA output of the unit, not on the fuel source or the prime mover force. Within a generating facility that aggregates to >75 MVA, there is no difference in the reliability benefit of a single wind turbine or a single gas fired turbine with the same MVA nameplate rating.
No
No
Group
Bonneville Power Administration
Andrea Jessup
Yes
No
(a) BPA feels that the term “dispersed generation resource” is typically associated with facilities that produce electric power through cogeneration and through renewable resources — such as biomass, solar, hydro, wind, municipal waste, tidal, wave, geothermal, and energy storage. It doesn’t matter which type of resource is used to generate power; what matters is the aggregated output at the

point of interconnection, which may have an effect on the electric power system. IEEE Standard 1001-1988 (IEEE Guide for Interfacing Dispersed Storage and Generation Facilities with Electric Utility Systems) and IEEE Standard 1547 (IEEE Standard for Interconnecting distributed Resources with Electric Power Systems) provide information regarding the technical aspects of dispersed generation resources. (b) BPA feels that for PRC-005 & PRC-023, the SAR needs to include individual turbine equipment dynamic response, such that the aggregate collector system provides the required relay response, not just the protective devices from the point of aggregation. It serves no reliability purpose if each turbine internally trips for a system event that requires continuation of the generation in a coordinated manner. (c) BPA feels that FAC-008 requires documentation from the generator to the high side of the main step-up transformer. For dispersed generation, this is the transformer at the main collector transformer. The SAR needs to consider including documentation for the collector system capability. BPA has found that when reactive current was not considered in earlier projects, overloads on some collectors were possible, which limited response to system events. (d) BPA has been requiring a collector system study provided by the generator owner to determine the reactive losses of the generation project and to ensure that reactive requirements are met. BPA has recently developed a collector system performance requirement to demonstrate compliance with reactive capability requirements. BPA recommends that this be added to the scope of the SAR to ensure that the generation in aggregate responds as required for a BES generation project.
No. BPA feels that a review of PRC-024 (Generator Frequency and Voltage Protective Relay Settings) needs to be included in the scope of this SAR. Aggregated dispersed generation must be able to ride-through faults and system disturbances the same as other generation resources.
No.
No.
Yes. IRO, MODs TOPs should be reported in aggregate. Outage coordination requirements for non-dispatchable generation should be eased as the certainty of the generation is never precisely known. BPA feels focusing compliance activities at the point of aggregation to 75 MVA is acceptable; however, there are a couple areas where we need to be cautious. One area of concern is the issue of back feed. Regardless of the size of the dispersed generation resource, proper precautions must be in place to ensure that it does not unintentionally or unexpectedly feed back into the BES. This is a matter of safety for personnel who might be doing construction or maintenance activities on the BES. BPA's other area of concern is the ability of the dispersed resources to ride through faults and system disturbances. BPA's concern here is similar to the concern BPA had when large amounts of wind generation began to be integrated into the grid. Specifically, BPA is concerned that the settings on protection schemes might be set such that large numbers of them would drop off during an event. This would be the equivalent of a large, high-speed spike in load, which could make the event far worse.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project 2014-01 Standards Applicability for Dispersed Generation Resources

The Project 2014-01 Standards Applicability for Dispersed Generation Resources (DGR) standards drafting team (SDT) thanks all commenters who submitted comments on the Standard Authorization Request (SAR) for this project. The SAR was posted for a 30-day formal comment period from November 20, 2013 through December 19, 2013. Stakeholders were asked to provide feedback on the SAR through a special electronic comment form. There were 28 sets of comments, including comments from approximately 98 different commenters from approximately 60 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the DGR project page.

The DGR SDT has carefully reviewed and considered each stakeholder comment in developing this summary response. In addition, the DGR SDT notes that it will not propose changes to the SAR because it believes the objectives of this project can be adequately addressed within the scope of the SAR.

1. General Scope and Objective of the SAR

Some commenters disagree with the scope and objective of the SAR because they believe, for example, that the Bulk Electric System (BES) definition has addressed the concerns raised in the SAR, and that the SAR is therefore not necessary. The DGR SDT disagrees. While the BES definition has identified certain dispersed power producing resources and their aggregating equipment relative to their inclusion as BES Facilities, it does not take into account that in order to maintain reliability of the BES and ensure appropriate use by entities of compliance and maintenance resources, certain reliability standards and their requirements should not or cannot be applied to dispersed generating facilities in the same manner as traditional generating resources. The SAR is therefore necessary to ensure that the facilities of dispersed generation resources are appropriately assigned responsibility for requirements that actually impact the reliability of the BES, as the characteristics of operating dispersed generation can be unique.

Some commenters would like to include standards not specifically identified in the SAR, for example, certain CIP, FAC, IRO, MOD, PRC, and TOP standards. The DGR SDT agrees that all NERC Standards should be reviewed as part of this project to determine whether changes are justified in order to account for the unique characteristics of dispersed generation, and has undertaken such a review. This review includes standards that are directly applicable to dispersed generation resources. For many standards, the concerns related to applicability to dispersed generation may be resolved through the publication of NERC guidance documentation in lieu of changes to the language of existing or future

reliability standards. The DGR SDT expects that the concerns with the majority of the standards will be addressed through this manner.

Some commenters note that the scope of the SAR should be expanded to include all small generators regardless of types. As noted in the SAR, the DGR SDT will consider those resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a collector system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. The DGR SDT believes that the scope of the current SAR allows for consideration of various generation designs when determining their impact upon the reliability of the BES. However, the DGR SDT notes that the impact that dispersed power producing resources (as described in the BES Definition reference document) could potentially have on the reliability of the BES is not necessarily the same impact that a traditional generator, regardless of size, will have, and must account for these differences when considering the applicability of any specific standard requirements.

At least one commenter suggested that for PRC-005 and PRC-023, the SAR needs to include individual turbine equipment dynamic response, such that the aggregate collector system provides the required relay response, not just the protective devices from the point of aggregation. The DGR SDT understands that there are certain reliability standards that may require applicability on Facilities below the point of aggregation at 75 MVA nameplate rating and is considering these functions in reviewing the applicability of specific requirements.

At least one commenter stated that the SAR does not make a coherent technical case for any standards changes. The DGR SDT will evaluate the merits of any proposed changes to the standards within the scope of the SAR and will seek to provide a detailed justification for proposed changes.

At least one commenter made suggestions to improve clarity of the SAR, e.g., changes to the “Industry Need” and “SAR Information” sections of the SAR. The DGR SDT will take those comments into account during the evaluation process to address the goals of this project and the revisions that are recommended.

The DGR SDT acknowledges that a number of comments support the initial scope of the SAR, with some additional recommendations regarding applicability. The DGR SDT feels that the scope of the current SAR allows for consideration of various generation designs when determining their impact upon the reliability of the BES.

2. BES Definition and Transition Period

At least one commenter expressed concern about the transition period for implementation of the BES definition and this project. The DGR SDT gives due consideration to the timing associated with

compliance requirements to include transition periods. This will encompass the transitional period associated with the BES definition.

The DGR SDT notes that the project schedule has been developed to take into account the July 1, 2016 compliance obligation date associated with the revised BES definition.

The DGR SDT also notes that it is focused on reliability in evaluating the standards but will remain mindful of the financial implications of compliance.

Some commenters suggest that the BES definition should be revised. The DGR SDT will not re-evaluate the BES definition, as it is beyond the scope of this project. The goal of the SAR is to revise the applicability of GO/GOP Reliability Standards or the applicability of requirements in GO/GOP Reliability Standards to recognize the unique technical and reliability aspects of dispersed generation, given the revised definition of the BES.

3. Canadian Provincial or other Regulatory Requirements

At least one commenter stated that there may be state regulatory requirements established for dispersed generation that may need to be considered in this project. The DGR SDT can make recommendations to Regional Entities that have approved Regional Reliability Standards; however, the DGR SDT cannot change those regional standards. Responsible entities may in fact be subject to additional regulatory requirements but such requirements are outside of NERC's sanctioned enforcement authorities and cannot be addressed in this process, but may be considered.

At least one commenter raised concerns about Quebec registration requirements. The DGR SDT does not believe it needs to specifically address the registration criteria of Canadian provinces. Although Quebec has unique registration values, it should not impact standard applicability.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you may contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

Index to Questions, Comments, and Responses

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The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Jeffrey Delgado	Caithness Shepherds Flat, LLC					X					
No Additional Responses													
2.	Group	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
No Additional Responses													
3.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	2
2.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
3.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
4.	Mike Kidwell	Empire District Electric	SPP	1
5.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
6.	Shannon Mickens	Southwest Power Pool	SPP	2
7.	Katy Onnen	Kansas City Power & Light	SPP	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
4.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	Mark Kenny	Northeast Utilities	NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC	5
12.	Helen Lainis	Independent Electricity System Operator	NPCC	2
13.	Michael Lombardi	Northeast Power Coordinating Council	NPCC	10
14.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
20.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
21.	Brian Robinson	Utility Services	NPCC	8
22.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
23.	Brian Shanahan	National Grid	NPCC	1
24.	Wayne Sipperly	New York Power Authority	NPCC	5
25.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
26.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

5.	Group	Russel Mountjoy	MRO NERC Standards Review Forum	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

2.	Chuck Wicklund	OtterTail Power Company	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	Western Area Power Administration	MRO	1, 6
7.	Joseph DePoorter	Madision Gas & Electric	MRO	3, 4, 5, 6
8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10.	Marie Knox	Midcontinent Independent System Operator	MRO	2
11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12.	Randi Nyholm	Minnesota Power	MRO	1, 5
13.	Scott Bos	Muscatine Power and Water	MRO	1, 3, 5, 6
14.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
15.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
16.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

6.	Group	Greg Campoli	ISO/RTO Council Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kathleen Goodman	ISO-NE	NPCC	2
2.	Cheryl Moseley	ERCOT	ERCOT	2
3.	Al DiCaprio	PJM	RFC	2
4.	Terry Bilke	MISO	MRO	2
5.	Charles Yeung	SPP	SPP	2
6.	Ben Li	IESO	NPCC	2

7.	Group	Ben Engelby	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Jackson	Buckeye Power, Inc.	RFC	3, 4
2.	Alisha Anker	Prairie Power, Inc.	SERC	3
3.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
4.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
5.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
8.	Group	Michael Lowman	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils		RFC	1
2.	Lee Schuster		FRCC	3
3.	Dale Goodwine		SERC	5
4.	Greg Cecil		RFC	6

9.	Group	Kathleen Black	DTE Electric			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kent Kujala	NERC Compliance	RFC	3
2.	Daniel Herring	NERC Training & Standards Development	RFC	4
3.	Mark Stefaniak	Regulated Marketing	RFC	5
4.	Barbara Holland		RFC	
5.	Neil Kennings		RFC	

10.	Group	Wayne Johnson	Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X				
No Additional Responses.													
11.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Anasis	Transmission Technical Operations	WECC	1
2.	Richard Becker	Transmission Substation Engineering	WECC	1
3.	Stephen Enyeart	Transmission Customer Service Engineering	WECC	1
4.	Fred Ojima	Transmission Planning	WECC	1
5.	Chuck Sheppard	Transmission Vegetation/Access Road Mgmt	WECC	1

12.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
13.	Individual	Shirley Mayadewi	Manitoba Hydro	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
14.	Individual	Patricia Metro	National Rural Electric Cooperative Association	X		X	X						
15.	Individual	David Jendras	Ameren	X		X	X	X					
16.	Individual	Silvia Parada Mitchell	NextEra Energy	X		X		X	X				
17.	Individual	Jonathan Meyer	Idaho Power	X									
18.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
19.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
20.	Individual	Barbara Kedrowski	Wisconsin Electric Power Company			X	X	X					
21.	Individual	Chris Scanlon	Exelon	X		X	X	X	X				
22.	Individual	David Greyerbiehl	Consumers Energy Company			X		X					
23.	Individual	Gary Kruempel	MidAmerican Energy Company	X		X		X	X				
24.	Individual	Bill Fowler	City of Tallahassee (TAL)			X							
25.	Individual	Scott Langston	City of Tallahassee	X									
26.	Individual	Carla L. Holly	BP Wind Energy North America Inc.					X					
27.	Individual	Karen Webb	City of Tallahassee					X					
28.	Individual	Peter A. Heidrich	Florida Reliability Coordinating Council, Inc.										X

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: The DGR SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Agree	Supporting Comments of "Entity Name"
NextEra Energy	Agree	MidAmerican
MidAmerican Energy Company		These comments were developed by NextERA (contact Brian Murhpy), MidAmerican, and Exelon

1. **Do you agree with the scope and objectives of this SAR? If not, please explain why you do not agree and, if possible, provide specific language revisions that would make it acceptable to you.**

Summary Consideration: The DGR SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Yes or No	Question 1 Comment
National Rural Electric Cooperative Association	No	NRECA does not believe this SAR is necessary. If entities with dispersed generation are registered as a Generator Owner (GO)/Generator Operator (GOP), it is the obligation of the registered entity to determine applicable standards and associated requirements and be able to explain how it complies accordingly. There is no need to modify the applicability of standards to specifically recognize dispersed generation as there is no recognizable reliability gap with the existing applicability of the standards included in this SAR.
Idaho Power	No	The BES definition in process has addressed the concerns raised in the SAR (in our opinion). Application of Standards applies to BES elements unless specifically excluded.
Public Service Enterprise Group	No	The SAR relies upon the phase 2 BES definition, as recently approved by the ballot body, but which has yet to be approved by the NERC Board or FERC. Under this definition, traditional generators at a site that exceed 75 MVA in aggregate as well as the all the equipment from terminals of each generator to the connection point with the BES are included in BES. Dispersed generators are treated differently. The individual dispersed generators are part of the BES if they are at a site where their aggregate nameplate capacity exceeds 75 MVA and they are connected to the BES; however, only equipment that delivers capacity from the point where those resources aggregate to greater than 75 MVA are included in the BES. Stated differently, traditional generators are contiguous with the BES, from the individual BES generators to their connection to the BES. Dispersed generators are not contiguous with the BES - the equipment that aggregate their output prior to it exceeding 75 MVA is excluded. These exclusions create a gap between dispersed BES generators and the BES they connect to. All generators should be treated comparably. The Eastern Interconnection Reliability

Organization	Yes or No	Question 1 Comment
		Assessment Group (ERAG) manual supports our recommendation regarding inclusion equipment for dispersed generators. Wind farm modeling, as specified in the ERAG manual, (https://rfirst.org/reliability/easterninterconnectionreliabilityassessmentgroup/mmwg/Documents/MMWG%20Procedure%20Manual%20V10.pdf) requires a high level of detail - see p. 30, item 6, which states: "Wind Farms - Include all 34.5 kV collector bus(es) and the main facility step-up transformer(s) from 34.5 kV to transmission voltage, as well as one 0.600 kV (or whatever the wind generator nominal voltage is) level bus off each collector bus with a lumped generator and lumped GSU representing the aggregate of the wind turbines attached to that collector bus and their GSUs." Thus, the ERAG manual requires modeling of non-BES Elements under phase 2 BES definition - see the BES Webinar slides nos. 5-7. (http://www.nerc.com/pa/Stand/WebinarLibrary/bes_phase2_third_posting_20131010_webinar_final.pdf) Setting aside our phase 2 definition concerns, the SAR does not make a coherent technical case for any standards changes. As an example, the justification for a change in PRC-005-2 has contradicting statements: "Manufacturers of dispersed generation turbines and solar panels recommend against specific testing and maintenance regimes for protection and control equipment at the dispersed generation turbine and panel level. In fact it is counterproductive to implement protection and control at the individual turbine, solar panel, or unit level. Instead this is best done at an aggregated level." In the first sentence, it appears that manufacturers install protection and control equipment at the "dispersed generation turbine and panel level," yet the next sentence states that "it is counterproductive to implement protection and control at the individual turbine, solar panel, or unit level." Which is it?During the balloting of PRC-005-2, no comments were submitted to the drafting team regarding the changes proposed in the SAR for PRC-005-2. Yet only a year after the final ballot on PRC-005-2, the SAR proposes changes to PRC-005-2 (and other standards) because the phase 2 definition, according to the SAR, would result in BES equipment at "dispersed generation facilities that if included under certain Reliability Standards may result in a detriment to reliability or be technically unsound and not useful to the support of the reliable operation of the BES." We believe that dispersed generators will have less equipment, not more, under the proposed BES definition because of the excluded equipment under that definition. Finally, there has been no justification put forth that would justify different

Organization	Yes or No	Question 1 Comment
		treatment of dispersed generation from traditional generation. See our remarks in questions 2 and 6 below.
Wisconsin Electric Power Company	No	The SAR needs to include applicability to CIP-002-5, proposed for the identification of BES Cyber Assets and BES Cyber Systems. If individual wind turbines are included in the BES, those cyber assets which support their operation (monitoring and control functions local to each turbine) would become BES Cyber Systems subject to some level of compliance requirements of the CIP v5 standards. The SAR needs to include all the CIP version 5 standards, including CIP-010 and CIP-011.Addtionally, these standards need to be listed:PRC-001/027 - Coordination for distributed resources needs to be accomplished with the collector system of the distributed resource, not with the transmission system. The collector system needs to be coordinated with the transmission system, however, the BES definition specifically excludes collector system equipment at less than 75 MVA from being included in the BES. PRC-024 - In most cases most distributed resources are many identical units. It would seem reasonable to document the relay data for one unit and then use it for many.PRC-019 - Voltage control for some types of dispersed generating facilities is accomplished by a controller that is able to adjust either generating unit controls or discrete reactive components to provide transmission system voltage adjustment. The PRC-019 standard should be modified to allow coordination with this type of control for dispersed generation facilities under the requirements of the standard.MOD 012/032 - In most cases most distributed resources are many identical units. It would seem reasonable to provide an example model of one resource and then use it for many.MOD 025 & 026 and 027 - In most cases most distributed resources are many identical units. It would seem reasonable to validate one unit and then use the results for many.
Florida Reliability Coordinating Council, Inc.	No	The SAR should not be limited to dispersed power producing resources only. A significant issue that will prove to derail this project is the potential inequitable treatment of generation. The scope should include all small generators regardless of fuel source or prime mover force. The scope should further identify small package style units that are typically considered 'run to fail' units. Provisions with in the 'Applicability' of the appropriate Reliability Standards that take

Organization	Yes or No	Question 1 Comment
		into account these types of units would significantly reduce the compliance obligations for units that simply are replaced (in whole)when a failure occurs.
ACES Standards Collaborators	Yes	We find this SAR timely and necessary to avoid confusion in the application of the revised definition of the Bulk Electric System.
MRO NERC Standards Review Forum	Yes	The SAR indicates several standards that should be considered for modification for dispersed generating units. It also provides for examination of other standards that may need to be similarly modified to accommodate the unique aspects of dispersed generation. In addition the SAR provides an explanation of which types of generation are to be reviewed in this project and this explanation is appropriate to define the scope of the project.
American Electric Power	Yes	AEP would prefer that the solution for applicability of dispersed generation at the turbine or generating unit level would be by adjusting the BES definition accordingly. Creating a new SAR, allowing this topic be discussed within the framework of the BES definition itself, would seem the most direct and efficient way of debating the topic. However, if that cannot be accomplished, AEP supports the effort of this SAR as an alternative (though less desirable) means to accomplish the same goal.
Ameren	Yes	(1) The proposed SAR appears to advocate the GSU as the Element within these standards' applicability, which appears reasonable for a SAR. However, we believe that this conflicts with the BES Definition Phase 2 Reference figures. Our expectation is that the BES Definition would be included in the scope of this SAR.
Xcel Energy	Yes	We strongly support the objective of this SAR.
Exelon	Yes	The SAR indicates several standards that should be considered for modification for dispersed generating units. It also provides for examination of other standards that may need to be similarly modified to accommodate the unique aspects of dispersed generation. In addition the SAR provides an explanation of which types of generation are to be reviewed in this project and this explanation is appropriate to define the scope of the project.

Organization	Yes or No	Question 1 Comment
MidAmerican Energy Company	Yes	The SAR indicates several standards that should be considered for modification for dispersed generating units. It also provides for examination of other standards that may need to be similarly modified to accommodate the unique aspects of dispersed generation. In addition the SAR provides an explanation of which types of generation are to be reviewed in this project and this explanation is appropriate to define the scope of the project.
City of Tallahassee (TAL)	Yes	Should the 75MVA be differentiated for Solar PV and other generating units that have both a DC and AC rating?
City of Tallahassee	Yes	Should the 75MVA be differentiated for Solar PV and other generating units that have both a DC and AC rating?
City of Tallahassee	Yes	Should the 75MVA be differentiated for Solar PV and other generating units that have both a DC and AC rating?
Caithness Shepherds Flat, LLC	Yes	
Arizona Public Service Company	Yes	
SPP Standards Review Group	Yes	
Northeast Power Coordinating Council	Yes	
ISO/RTO Council Standards Review Committee	Yes	

Organization	Yes or No	Question 1 Comment
Duke Energy	Yes	
DTE Electric	Yes	
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
Bonneville Power Administration	Yes	
Manitoba Hydro	Yes	
Consumers Energy Company	Yes	
BP Wind Energy North America Inc.	Yes	

2. Do you agree that the scope of the SAR should be limited to considering revisions necessary to address the unique technical and reliability aspects of dispersed generation resources, or should the scope encompass consideration of changes to standards applicability for all small generation regardless of type? Please provide a technical rationale for your response.

Summary Consideration: The DGR SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Yes or No	Question 2 Comment
Arizona Public Service Company	No	Scope should expanded to include all small generators regardless of types. There is no specific reason to not include all. Generally, there is little reliability benefits to BES by applying NERC standards to small generators regardless of the type.
SPP Standards Review Group	No	We believe that this evaluation should be extended to all small generation regardless of type because the impact on the BES would be the same regardless of the source or prime mover of the generation.
ACES Standards Collaborators	No	No, we do not agree that the scope of the SAR should be limited. The scope of the SAR should be to review standards applicable to GO/GOP and to limit the applicability based on the revised definition of the BES. Small generation regardless of type should be included in this review.
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company	No	We believe the scope should include consideration of changes to standards applicability for all small generation. In particular, individual generators < 75 MVA should be exempted from model validation requirements unless transmission planning studies demonstrate such individual generators are critical to BES reliability. This would significantly reduce the compliance burdens being imposed on many GOs and GOPs and improve the focus on generators that are critical to reliability.

Organization	Yes or No	Question 2 Comment
Generation and Energy Marketing		
Bonneville Power Administration	No	(a) BPA feels that the term “dispersed generation resource” is typically associated with facilities that produce electric power through cogeneration and through renewable resources - such as biomass, solar, hydro, wind, municipal waste, tidal, wave, geothermal, and energy storage. It doesn’t matter which type of resource is used to generate power; what matters is the aggregated output at the point of interconnection, which may have an effect on the electric power system. IEEE Standard 1001-1988 (IEEE Guide for Interfacing Dispersed Storage and Generation Facilities with Electric Utility Systems) and IEEE Standard 1547 (IEEE Standard for Interconnecting distributed Resources with Electric Power Systems) provide information regarding the technical aspects of dispersed generation resources.(b) BPA feels that for PRC-005 & PRC-023, the SAR needs to include individual turbine equipment dynamic response, such that the aggregate collector system provides the required relay response, not just the protective devices from the point of aggregation. It serves no reliability purpose if each turbine internally trips for a system event that requires continuation of the generation in a coordinated manner.(c) BPA feels that FAC-008 requires documentation from the generator to the high side of the main step-up transformer. For dispersed generation, this is the transformer at the main collector transformer. The SAR needs to consider including documentation for the collector system capability. BPA has found that when reactive current was not considered in earlier projects, overloads on some collectors were possible, which limited response to system events.(d) BPA has been requiring a collector system study provided by the generator owner to determine the reactive losses of the generation project and to ensure that reactive requirements are met. BPA has recently developed a collector system performance requirement to demonstrate compliance with reactive capability requirements. BPA recommends that this be added to the scope of the SAR to ensure that the generation in aggregate responds as required for a BES generation project.

Organization	Yes or No	Question 2 Comment
American Electric Power	No	We believe it is preferable, at least initially, for the scope to remain limited to dispersed generation resources.
National Rural Electric Cooperative Association	No	See response to Question 1
Idaho Power	No	I see no need for a SAR.
Public Service Enterprise Group	No	As stated previously, “small generators” (traditional versus dispersed) are not treated comparably in the phase 2 definition - traditional BES generators must be contiguous with the BES but dispersed generators need not be. While we would welcome changes that provide for comparable treatment for small generators, regardless of type, the unequal treatment embedded in the phase 2 definition must be corrected before those changes are considered.
Florida Reliability Coordinating Council, Inc.	No	The scope should include all small generators regardless of fuel source or prime mover force. The scope should further identify small package style units that are typically considered 'run to fail' units. The reliability benefit of a generating facility is based on the MVA output of the unit, not on the fuel source or the prime mover force. Within a generating facility that aggregates to >75 MVA, there is no difference in the reliability benefit of a single wind turbine or a single gas fired turbine with the same MVA nameplate rating.
Caithness Shepherds Flat, LLC	Yes	Caithness Shepherds Flat Wind Farm (CSF), located in Oregon, supports the SAR as written and believes the scope should address dispersed generation resources with collector systems only. In the development of CSF’s NERC compliance program, it became apparent that some GO/GOP applicable Reliability Standards were written with fossil fuel facilities in mind, and not generation resources such as wind. The VAR-002 standard for example, requiring reactive and voltage control of individual generators and notification of the TOP when there is a change in status, would appear to be irrelevant to the TOP, but rather the aggregate MW output at the point

Organization	Yes or No	Question 2 Comment
		of interconnection should be what is relevant. CSF's wind farm consists of several hundred wind turbines, all < 3 MW in nameplate capacity. The TOP does not need to be notified about individual turbine voltage status, as any loss of voltage control of an individual turbine will not be detected by the TOP. The relevant factor is in the voltage at the point of interconnection which is controlled by a "Wind Farm Management System" WFMS voltage control system. Change in status of the WFMS would be of interest to the TOP, so the standard should allow for this variance.
MRO NERC Standards Review Forum	Yes	The SAR does not specify what types of generation should be included for analysis as "dispersed generation resources. It only refers to those that are a part of a facility that aggregates to 75 MVA or more. As written the SAR is not limited to any particular type of small generation. Under the SAR all types could and should be considered for revision.
ISO/RTO Council Standards Review Committee	Yes	Small generators that do not meet the individual 20 MVA criteria and are not part of the aggregated 75 MVA group that meets the BES inclusion criteria are not regarded BES facilities and therefore do not need to be addressed by this SAR. The scope therefore does not need to be expanded to all small generators.
Duke Energy	Yes	(1) Duke Energy agrees that the scope of the SAR should be limited to Disperse Generation only.
MidAmerican Energy Company	Yes	The SAR does not specify what types of generation should be included for analysis as "dispersed generation resources. It only refers to those that are a part of a facility that aggregates to 75 MVA or more. As written the SAR is not limited to any particular type of small generation. Under the SAR all types could and should be considered for revision.
City of Tallahassee (TAL)	Yes	Dispersed generation should include intermittent power sources such as wind and solar, but also non-intermittent such as WTE, biogas and biomass generation sources.

Organization	Yes or No	Question 2 Comment
City of Tallahassee	Yes	Dispersed generation should include intermittent power sources such as wind and solar, but also non-intermittent such as WTE, biogas and biomass generation sources.
BP Wind Energy North America Inc.	Yes	The scope of the SAR should be limited to considering revisions necessary to address the unique technical and reliability aspects of dispersed generation resources as dispersed generation resources are unique and have operational characteristics that are not similar to most conventional generators, including generators that are considered to be classified as small.
City of Tallahassee	Yes	Dispersed generation should include intermittent power sources such as wind and solar, but also non-intermittent such as waste-to-energy, biogas, and biomass generation sources.
Exelon	Yes	Yes, the SAR should focus on generation resources that are part of a facility that aggregates dispersed resources at 75 MVA or more. We believe the intent is to exclude individual units from certain requirements when those units do not meet the reporting criteria but are part of a facility that aggregates those units at the BES voltage level. We note that the question may lead to confusion. As written the use of "or" appears to be implying there is a choice between "dispersed generation" as used in the first clause of the question and some generation "types" (undefined but commonly understood to refer to fuel source) as used in the second clause. We do not believe the SAR should exclude generation based on fuel type.
DTE Electric	Yes	
Manitoba Hydro	Yes	
Ameren	Yes	
Consumers Energy Company	Yes	

3. Do you agree with the list of standards to be reviewed? If you do not agree, please note specific standards you think should be added to or removed from the list.

Summary Consideration: The DGR SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Question 3 Comment
American Electric Power	Every standard that involves the GO and/or GOP should be included in the scope of the SAR. This does not imply that all standards should be modified, but the SDT and commenters should be afforded the opportunity to consider the impacts of such changes. For example, PRC-024, PRC-001, CIP-002 through CIP-011, etc. should be considered.
Public Service Enterprise Group	No comments
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No. Need to also add those included in the Generator Verification Standard suite, including PRC-019, PRC-024, MOD-025, MOD-026, MOD-027. We are concerned with how certain standard requirements such as VAR-002 R3 can be applied to facilities with multiple "mini" units operating in parallel. For example, in the case of small turbine-generators one or more units operating in manual regulator mode would not have the same impact to the BES as a single large unit. Similar issues exist when some of the other listed standard requirements are applied such as model validation of excitation systems and governors (MOD-026 & MOD-027, as noted above).
Bonneville Power Administration	No. BPA feels that a review of PRC-024 (Generator Frequency and Voltage Protective Relay Settings) needs to be included in the scope of this SAR. Aggregated dispersed generation must be able to ride-through faults and system disturbances the same as other generation resources.

Organization	Question 3 Comment
Wisconsin Electric Power Company	Response from Q1:The SAR needs to include applicability to CIP-002-5, proposed for the identification of BES Cyber Assets and BES Cyber Systems. If individual wind turbines are included in the BES, those cyber assets which support their operation (monitoring and control functions local to each turbine) would become BES Cyber Systems subject to some level of compliance requirements of the CIP v5 standards. The SAR needs to include all the CIP version 5 standards, including CIP-010 and CIP-011.Addtionally, these standards need to be listed:PRC-001/027 - Coordination for distributed resources needs to be accomplished with the collector system of the distributed resource, not with the transmission system. The collector system needs to be coordinated with the transmission system, however, the BES definition specifically excludes collector system equipment at less than 75 MVA from being included in the BES. PRC-024 - In most cases most distributed resources are many identical units. It would seem reasonable to document the relay data for one unit and then use it for many.PRC-019 - Voltage control for some types of dispersed generating facilities is accomplished by a controller that is able to adjust either generating unit controls or discrete reactive components to provide transmission system voltage adjustment. The PRC-019 standard should be modified to allow coordination with this type of control for dispersed generation facilities under the requirements of the standard.MOD 012/032 - In most cases most distributed resources are many identical units. It would seem reasonable to provide an example model of one resource and then use it for many.MOD 025 & 026 and 027 - In most cases most distributed resources are many identical units. It would seem reasonable to validate one unit and then use the results for many.
National Rural Electric Cooperative Association	See response to Question 1
MRO NERC Standards Review Forum	The SAR provides a list of several specific standards application to Generator Owners and/or Generator Operators that would be reviewed as part of the project. In addition it proposes a review of several project families (IRO,MOD, PRC and TOP) that would be examined. The specific list is recommended as proposed in the SAR and with the flexibility to review other standards the list as indicated is appropriate Consideration should be given to an addition to the Attachment in CIP-002 to add an item that would exclude components below the 75MVA aggregation point. The

Organization	Question 3 Comment
	reasoning would be parallel to the other standards addressed in the SAR where the aggregation point would be identified as the point at which the standard would apply. For CIP the result would be that the components below the aggregation point would not have to be addressed, i.e. they would not be high, medium, or low.
Exelon	The SAR provides a list of several specific standards application to Generator Owners and/or Generator Operators that would be reviewed as part of the project. In addition it proposes a review of several project families (IRO,MOD, PRC and TOP) that would be examined. The specific list is recommended as proposed in the SAR and with the flexibility to review other standards the list as indicated is appropriate.
MidAmerican Energy Company	The SAR provides a list of several specific standards application to Generator Owners and/or Generator Operators that would be reviewed as part of the project. In addition it proposes a review of several project families (IRO,MOD, PRC and TOP) that would be examined. The specific list is recommended as proposed in the SAR and with the flexibility to review other standards the list as indicated is appropriate Consideration should be given to an addition to the Attachment in CIP-002 to add an item that would exclude components below the 75MVA aggregation point. The reasoning would be parallel to the other standards addressed in the SAR where the aggregation point would be identified as the point at which the standard would apply. For CIP the result would be that the components below the aggregation point would not have to be addressed, i.e. they would not be high, medium, or low.
ACES Standards Collaborators	We agree with the list of standards to be reviewed. We would like to see flexibility in the scope of standards to be reviewed in the event that another standard is added during the standards development phase.
Xcel Energy	We believe that in addition to the approved standards mentioned in the SAR, NERC should communicate this issue directly to drafting teams working on active projects such as PRC-004-3 or PRC-027-1 to assure that they consider the applicability of their standard relative to dispersed generation and, if it is intended to include dispersed generation as in scope, to assure that correct

Organization	Question 3 Comment
	terminology is used within their draft standard to avoid ambiguity and inconsistencies such as the SAR discusses for use of the term "main step up transformer" in FAC-008-3.
SPP Standards Review Group	While we may agree with the list of standards as presented in the SAR we would encourage the SAR drafting team to not limit itself to just those particular standards. For example, once a drafting team is established and work begins on the project, we don't want the project to be limited by the scope as currently defined in the SAR. We need to factor in some flexibility to go beyond this specific list to capture all those standards/requirements/definitions which may be impacted in this review.
Caithness Shepherds Flat, LLC	Yes
Arizona Public Service Company	Yes
ISO/RTO Council Standards Review Committee	Yes
Consumers Energy Company	Yes
City of Tallahassee (TAL)	yes
City of Tallahassee	Yes
Ameren	Yes, we agree.
Northeast Power Coordinating Council	Yes.

Organization	Question 3 Comment
BP Wind Energy North America Inc.	Yes. We agree with the list of standards to be reviewed; however, we suggest more clarification about which specific IRO, MOD, PRC, and TOP standards would be considered as the SAR currently lists these categories generically.
DTE Electric	YesAs stated in the background information, any relevant standard should be revised as necessary to insure that it is being applied at the point of aggregation.

4. Are you aware of any business practice that will be needed or that will need to be modified as a result of this SAR should it move forward? If yes, please identify the business practice.

Summary Consideration: The DGR SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Question 4 Comment
Caithness Shepherds Flat, LLC	No
Arizona Public Service Company	No
ISO/RTO Council Standards Review Committee	No
DTE Electric	No
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No
Manitoba Hydro	No

Organization	Question 4 Comment
Idaho Power	No
Exelon	No
MidAmerican Energy Company	No
City of Tallahassee	No
Florida Reliability Coordinating Council, Inc.	No
Public Service Enterprise Group	No comments
Northeast Power Coordinating Council	No.
ACES Standards Collaborators	No.
Bonneville Power Administration	No.
American Electric Power	No.
BP Wind Energy North America Inc.	No.
City of Tallahassee (TAL)	No. The City of Tallahassee is not aware of other business practices to be included.
SPP Standards Review Group	Not at this time.

Organization	Question 4 Comment
Consumers Energy Company	The SAR is required at a minimum, but a change to the BES definition is more appropriate.From the comments below submitted during the BES, the BES definition should at minimum be modified to provide consistency between generating resources (I2) and dispersed power producing resources (I4). Generating resources are required to be 20MVA in order to be considered an BES element, while dispersed power producing resources have no size consideration as long as they meet the net total MVA. Consumers Energy has completed studies with an operating wind farms and the loss of individual resources makes no impact the BES. The addition of individual resources does not make improve reliability as they have no effect on the system.The SAR intention is to modify the individual standards to define the requirements for all the additional BES elements that are being added that are not presently addressed in the standards or are against the manufacturers recommendations. While this approach can be used, and is required if the BES definition is not changed. A better method would be to include dispersed power producing resources at a point in which the total affects the BES and not as individual units.Previous Comments on BES definition:The inclusion and the clarification of the inclusion seem to contradict each other. The highlight portion above seems to indicate inclusion only from the point of aggregation of 75MVA or above. This, in most Wind Park cases would include a collector bus but probably not individual wind turbines. However I4 seems to indicate that the case of a Wind Park that has a total aggregation of 75 MVA, all associated equipment including every individual wild turbine would be included. There is inconsistency.If and when Distributed Generation gains saturation is it our intent that whole neighborhoods or industrial parks be considered BES resources? Technical justification should be needed to include resources in the BES, not the other way around. Is there a real expectation that a single collector circuit containing ten, 1.2MW wind turbines can cause cascading or uncontrollable outages of the surrounding system? It is extremely doubtful. We can support the inclusion of equipment where the aggregation of 75 MVA or more connects to the Bulk Electric System at voltages of 100kv or greater. There is a clear indication here that a single contingency can remove the total of the capacity from the system where with this definition as proposed, that is simply not the case.

5. Are you aware of any Canadian provincial or other regulatory requirements that may need to be considered during this project in order to develop a continent-wide approach to the standard(s)? If yes, please identify the jurisdiction and specific regulatory requirements.

Summary Consideration: The DGR SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Question 5 Comment
SPP Standards Review Group	Although we are not aware of any specific federal regulatory requirements, the drafting team needs to keep in mind that there may be state regulatory requirements established for dispersed generation that may need to be considered in this project.
Idaho Power	N/A
Caithness Shepherds Flat, LLC	No
Arizona Public Service Company	No
ISO/RTO Council Standards Review Committee	No
DTE Electric	No
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation;	No

Organization	Question 5 Comment
Southern Company Generation and Energy Marketing	
Manitoba Hydro	No
Exelon	No
Consumers Energy Company	No
MidAmerican Energy Company	No
City of Tallahassee	No
Public Service Enterprise Group	No comments
ACES Standards Collaborators	No.
Bonneville Power Administration	No.
American Electric Power	No.
BP Wind Energy North America Inc.	No.
City of Tallahassee (TAL)	No. The City of Tallahassee is not aware of such.

Organization	Question 5 Comment
Northeast Power Coordinating Council	Yes.It must be considered that the operating system in Quebec follows chapter R-6.01 An Act Respecting the Regie de L'Energie, which details:(1) an owner or operator of a facility with a capacity of 44 kV or more connected to an electric power transmission system;(2) an owner or operator of an electric power transmission system;(3) an owner or operator of a production facility with a capacity of 50 megavolt amperes (MVA) or more connected to an electric power transmission system;(4) a distributor with a peak capacity of over 25 megawatts (MW), whose facilities are connected to an electric power transmission system; and(5) a person who uses an electric power transmission system under an electric power transmission service agreement with the electric power carrier or with any other carrier in QuÃ©bec.

6. Are there any other concerns with this SAR that haven't been covered in previous questions?

Summary Consideration: The DGR SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Question 6 Comment
Arizona Public Service Company	No
Caithness Shepherds Flat, LLC	No
City of Tallahassee	No
Consumers Energy Company	No
DTE Electric	No
Florida Reliability Coordinating Council, Inc.	No
ISO/RTO Council Standards Review Committee	No
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company	No

Organization	Question 6 Comment
Generation and Energy Marketing	
ACES Standards Collaborators	No other concerns.
American Electric Power	No.
City of Tallahassee (TAL)	No.
Northeast Power Coordinating Council	No.
BP Wind Energy North America Inc.	No.
SPP Standards Review Group	Regarding the July 2016 deadline, the drafting team needs to be sure that this effort is complete in time for the industry to be ready by July 2016. We need to be sure that as the deadline approaches, compliance preparations aren't made and then un-made as a result of a modification to an existing standard which is impacted by this effort.In the 1st line of the 1st paragraph of the Industry Need section under SAR Information, we suggest replacing 'application' with 'applicability'.In the 5th line of the 1st paragraph of the Brief Description section under SAR Information, replace 'real time' with 'Real-time', the NERC Glossary term.In the 1st line of the FAC-008-3 paragraph under SAR Information, hyphenate step-up.In the next to last line of the General review of IROs, MODs, PRCs, TOPs paragraph, change 'uneeded' to 'unneeded'.
Public Service Enterprise Group	Section 303 of the NERC ROP addresses "Relationship between Reliability Standards and Competition." Item 1 states: "Competition - A Reliability Standard shall not give any market participant an unfair competitive advantage." By not treating all generators comparably, the SAR violates item 1. Based upon this and our prior comments, we recommend that the SAR be rejected by the Standards Committee.

Organization	Question 6 Comment
Exelon	The SAR includes the objective to complete the changes and obtain regulatory approval prior to the completion of the implementation of the BES definition. It is essential that this schedule is met so that dispersed generation owners and operators can plan and implement their compliance programs without having to temporarily implement requirements that will be superseded by this project.
	The SAR includes the objective to complete the changes and obtain regulatory approval prior to the completion of the implementation of the BES definition. It is essential that this schedule is met so that dispersed generation owners and operators can plan and implement their compliance programs without having to temporarily implement requirements that will be superseded by this project.
MRO NERC Standards Review Forum	The SAR includes the objective to complete the changes and obtain regulatory approval prior to the completion of the implementation of the BES definition. It is essential that this schedule is met so that dispersed generation owners and operators can plan and implement their compliance programs without having to temporarily implement requirements that will be superseded by this project.
Bonneville Power Administration	Yes. IRO, MODs TOPs should be reported in aggregate. Outage coordination requirements for non-dispatchable generation should be eased as the certainty of the generation is never precisely known.BPA feels focusing compliance activities at the point of aggregation to 75 MVA is acceptable; however, there are a couple areas where we need to be cautious. One area of concern is the issue of back feed. Regardless of the size of the dispersed generation resource, proper precautions must be in place to ensure that it does not unintentionally or unexpectedly feed back into the BES. This is a matter of safety for personnel who might be doing construction or maintenance activities on the BES.BPA's other area of concern is the ability of the dispersed resources to ride through faults and system disturbances. BPA's concern here is similar to the concern BPA had when large amounts of wind generation began to be integrated into the grid. Specifically, BPA is concerned that the settings on protection schemes might be set such that large

Organization	Question 6 Comment
	numbers of them would drop off during an event. This would be the equivalent of a large, high-speed spike in load, which could make the event far worse.
	(1) Apply the Generator Site Boundary used in the BES Definition Reference (e.g. Figure I2-5) consistently for dispersed generation so that multiple GSU do not circumvent the 75MVA aggregate.(2) Develop a NERC Glossary definition for the term 'dispersed generation'.
Duke Energy	(1) Duke Energy is concerned that Dispersed Generation will have to be compliant with the BES definition Phase 1 prior to the Implementation of this Project and the implementation of Phase 2 of the BES definition.(2) Financial implications to registered entities should be considered and included in the Industry Need section of the SAR such as additional human resources required to maintain compliance if the standards are not revised for the applicability of dispersed generation resources at the point of aggregation to 75 MVA or greater.
Manitoba Hydro	Although we do not have any concerns with this SAR, we have the following suggestions to improve clarity.(1) Industry Need - remove the words "Bulk Electric System" from the second paragraph to leave only the acronym, BES because this is the second instance of BES in the document. (2) SAR Information - capitalize 'misoperation' because it appears in the Glossary of Terms.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.

Description of Current Draft

PRC-001-1.1(X)[1] is proposed for approval to align the applicability of PRC-001-1.1a with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 – Standards Applicability for Dispersed Generation Resources standards drafting team (SDT) has coordinated with the other SDTs currently reviewing this standard and has recommended revisions to Requirement R3.1 to account for the unique characteristics of dispersed power producing resources.[2] Given the timing of concurrent standards development of PRC, TOP, and IRO projects, PRC-001-1.1a may be retired pursuant to an Implementation Plan of a successor version of PRC-001. If this occurs, PRC-001-1.1(X) will not go into effect. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.

Anticipated Actions	Anticipated Date
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	December 2014
Final ballot	January 2015
BOT adoption	February 2015

[1] The standard version number currently includes an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to adoption by the NERC Board of Trustees.

[2] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

1. Title: System Protection Coordination

2. Number: PRC-001-1.1(X)

3. Purpose:

To ensure system protection is coordinated among operating entities.

4. Applicability

4.1. Balancing Authorities

4.2. Transmission Operators

4.3. Generator Operators

5. Effective Date:

See the Implementation Plan for this standard.

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:

R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.

R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.

- Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

Rationale for the Applicability Exclusion in Requirement R3.1

Coordination of new or changes to protective systems associated with dispersed power producing resources identified through Inclusion I4 of the BES definition are typically performed on the interconnecting facilities. New or changes to protective systems associated with these facilities should be coordinated with the TOP as these protective systems typically must be closely coordinated with the transmission protective systems to ensure the overall protection systems operates as designed. While the protective systems implemented on the individual generating units of dispersed power producing resources at these dispersed power producing facilities (i.e. individual wind turbines or solar panels/inverters) may in some cases need to be coordinated with other protective systems within the same dispersed power producing facility, new or changes to these protective systems do not need to be coordinated with the transmission protective systems, as this coordination would not provide reliability benefits to the BES.

R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.

R4. Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:

R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.

R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.

R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

C. Measures

M1. Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic

logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Special Protection Systems in its area. (Requirement 6 Part 1)

M3. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Special Protection Systems. (Requirement 6 Part 2)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures 2 and 3.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Generator Operators:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

3. Levels of Non-Compliance for Transmission Operators:

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

3.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Failed to provide evidence of coordination when installing new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities as specified in R3.2.

3.4.2 Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

4. Levels of Non-Compliance for Balancing Authorities:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	August 25, 2005	Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0	Errata
1	November 1, 2006	Adopted by the NERC Board of Trustees	Revised
1.1	April 11, 2012	Errata adopted by the Standards Committee; (Capitalized "Protection System" in accordance with Implementation Plan for Project 2007-17 approval of revised definition of "Protection System")	Errata associated with Project 2007-17
1.1	September 9, 2013	Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.	
TBD (balloted as 1.1(X))	TBD	Standard revised in Project 2014-01	Applicability revised to clarify application of requirements to BES dispersed power producing resources

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.

Description of Current Draft

PRC-001-1.1(X)[1] is proposed for approval to align the applicability of PRC-001-1.1a with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 – Standards Applicability for Dispersed Generation Resources standards drafting team (SDT) has coordinated with the other SDTs currently reviewing this standard and has recommended revisions to Requirement R3.1 to account for the unique characteristics of dispersed power producing resources.[2] Given the timing of concurrent standards development of PRC, TOP, and IRO projects, PRC-001-1.1a may be retired pursuant to an Implementation Plan of a successor version of PRC-001. If this occurs, PRC-001-1.1(X) will not go into effect. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.

Anticipated Actions	Anticipated Date
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	December 2014
Final ballot	January 2015
BOT adoption	February 2015

[1] The standard version number currently includes an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to adoption by the NERC Board of Trustees.

[2] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

1. **Title:** **System Protection Coordination**

2. **Number:** PRC-001-1.1(X)

3. **Purpose:**

   To ensure system protection is coordinated among operating entities.

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Transmission Operators

   4.3. Generator Operators

5. **Effective Date:** ~~January 1, 2007~~

   See the Implementation Plan for this standard.

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:

R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.

R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.

- Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

Rationale for the Applicability Exclusion in Requirement R3.1

Coordination of new or changes to protective systems associated with dispersed power producing resources identified through Inclusion I4 of the BES definition are typically performed on the interconnecting facilities. New or changes to protective systems associated with these facilities should be coordinated with the TOP as these protective systems typically must be closely coordinated with the transmission protective systems to ensure the overall protection systems operates as designed. While the protective systems implemented on the individual generating units of dispersed power producing resources at these dispersed power producing facilities (i.e. individual wind turbines or solar panels/inverters) may in some cases need to be coordinated with other protective systems within the same dispersed power producing facility, new or changes to these protective systems do not need to be coordinated with the transmission protective systems, as this coordination would not provide reliability benefits to the BES.

R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.

R4. Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:

R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.

R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.

R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

C. Measures

M1. Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic

logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Special Protection Systems in its area. (Requirement 6 Part 1)

M3. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Special Protection Systems. (Requirement 6 Part 2)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures 2 and 3.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Generator Operators:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

3. Levels of Non-Compliance for Transmission Operators:

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

3.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Failed to provide evidence of coordination when installing new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities as specified in R3.2.

3.4.2 Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

4. Levels of Non-Compliance for Balancing Authorities:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	August 25, 2005	Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0	Errata
1	November 1, 2006	Adopted by the NERC Board of Trustees	Revised
1.1	April 11, 2012	Errata adopted by the Standards Committee; (Capitalized "Protection System" in accordance with Implementation Plan for Project 2007-17 approval of revised definition of "Protection System")	Errata associated with Project 2007-17
1.1	September 9, 2013	Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.	
TBD (balloted as 1.1(X))	TBD	Standard revised in Project 2014-01	Applicability revised to clarify application of requirements to BES dispersed power producing resources

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.

Description of Current Draft

PRC-019-2 is proposed for approval to align the applicability section of PRC-019-1 with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 – Standards Applicability for Dispersed Generation Resources standards drafting team has recommended revisions to the Facilities section to clarify that facilities that solely regulate voltage at the individual generating unit are subject to the requirements. Given the timing of concurrent standards development of PRC projects, PRC-019-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-019. If this occurs, PRC-019-2 will not go into effect. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.[1]

Anticipated Actions	Anticipated Date
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	December 2014
Final ballot	January 2015
BOT adoption	February 2015

[1] The terms “dispersed generation resources” and “dispersed power producing resources” are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

1. **Title:** Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

2. **Number:** PRC-019-2

3. **Purpose:** To verify coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings.

4. **Applicability:**

   4.1. Functional Entities

   4.1.1 Generator Owner

   4.1.2 Transmission Owner that owns synchronous condenser(s)

   4.2. Facilities

   For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following:

   4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

   4.2.2 Individual synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

   4.2.3 Generating plant/ Facility consisting of one or more units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

   4.2.3.1 This includes individual dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition where voltage regulating control for the facility is performed solely at the individual resources.

Rationale for Facilities section 4.2.3.1

For those dispersed power producing facilities that only perform voltage regulating control at the individual unit level, the SDT believes that coordination should take place at the individual power producing resource level. These facilities need to consider the Protection Systems at the individual units and their compatibility with the reactive and voltage limitations of the units. Where voltage regulating control is done at an aggregate level, applicability is already included under Facilities section 4.2.3.

4.2.4 Any generator, regardless of size, that is a blackstart unit material to and designated as part of a Transmission Operator's restoration plan.

5. Effective Date:

See the Implementation Plan for this standard.

B. Requirements

R1. At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls, (including in-service[2] limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Assuming the normal automatic voltage regulator control loop and steady-state system operating conditions, verify the following coordination items for each applicable Facility:

1.1.1. The in-service limiters are set to operate before the Protection System of the applicable Facility in order to avoid disconnecting the generator unnecessarily.

1.1.2. The applicable in-service Protection System devices are set to operate to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits.

R2. Within 90 calendar days following the identification or implementation of systems, equipment or setting changes that will affect the coordination described in Requirement R1, each Generator Owner and Transmission Owner with applicable Facilities shall perform the coordination as described in Requirement R1. These possible systems, equipment or settings changes include, but are not limited to the following *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

- Voltage regulating settings or equipment changes;
- Protection System settings or component changes;
- Generating or synchronous condenser equipment capability changes; or
- Generator or synchronous condenser step-up transformer changes.

C. Measures

M1. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence (such as examples provided in PRC-019 Section G) that it coordinated the voltage regulating system controls, including in-service[3] limiters and protection functions, with the applicable equipment capabilities and settings of the applicable

[2] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

[3] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

Protection System devices and functions as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed.

M2. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence of the coordination required by the events listed in Requirement R2. This evidence should include dated documentation that demonstrates the specified intervals in Requirement R2 have been met.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention

The following evidence retention periods identify a period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention specified below is shorter than the time since the last compliance audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Owner shall retain evidence of compliance with Requirements R1 and R2, Measures M1 and M2 for six years.

If a Generator Owner or Transmission Owner is found non-compliant, the entity shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last periodic audit report and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years but less than or equal to 5 calendar years plus 4 months after the previous coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years plus 4 months but less than or equal to 5 calendar years plus 8 months after the previous coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years plus 8 months but less than or equal to 5 calendar years plus 12 months after the previous coordination.	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 5 calendar years plus 12 months after the previous coordination.
R2	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 90 calendar days but less than or equal to 100 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 100 calendar days but less than or equal to 110 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 110 calendar days but less than or equal to 120 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 120 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.

E. Regional Variances

None.

F. Associated Documents

"Underexcited Operation of Turbo Generators", AIEE Proceedings T Section 881, Volume 67, 1948, Appendix 1, C. G. Adams and J. B. McClure.

,"Protective Relaying For Power Generation Systems", Boca Raton, FL, Taylor & Francis, 2006, Reimert, Donald

"Coordination of Generator Protection with Generator Excitation Control and Generator Capability", a report of Working Group J5 of the IEEE PSRC Rotating Machinery Subcommittee

"IEEE C37.102-2006 IEEE Guide for AC Generator Protection"

"IEEE C50.13-2005 IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above"

Version History

Version	Date	Action	Change Tracking
1	February 7, 2013	Adopted by NERC Board of Trustees	New
1	March 20, 2014	FERC Order issued approving PRC-019-1. (Order becomes effective on 7/1/16.)	

G. Reference

Examples of Coordination

The evidence of coordination associated with Requirement R1 may be in the form of:

- P-Q Diagram (Example in Attachment 1), or
- R-X Diagram (Example in Attachment 2), or
- Inverse Time Diagram (Example in Attachment 3) or,
- Equivalent tables or other evidence

This evidence should include the equipment capabilities and the operating region for the limiters and protection functions

Equipment limits, types of limiters and protection functions which could be coordinated include (but are not limited to):

- Field over-excitation limiter and associated protection functions.
- Inverter over current limit and associated protection functions.
- Field under-excitation limiter and associated protection functions.
- Generator or synchronous condenser reactive capabilities.
- Volts per hertz limiter and associated protection functions.
- Stator over-voltage protection system settings.
- Generator and transformer volts per hertz capability.
- Time vs. field current or time vs. stator current.

NOTE: This listing is for reference only. This standard does not require the installation or activation of any of the above limiter or protection functions.

For this example, the Steady State Stability Limit (SSSL) is the limit to synchronous stability in the under-excited region with fixed field current.

On a P-Q diagram using X_d as the direct axis saturated synchronous reactance of the generator, X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer and V_g as the generator terminal voltage (all values in per-unit), the SSSL can be calculated as an arc with the center on the Q axis with the magnitude of the center and radius described by the following equations

$$C = V^2_g/2*(1/X_s-1/X_d)$$

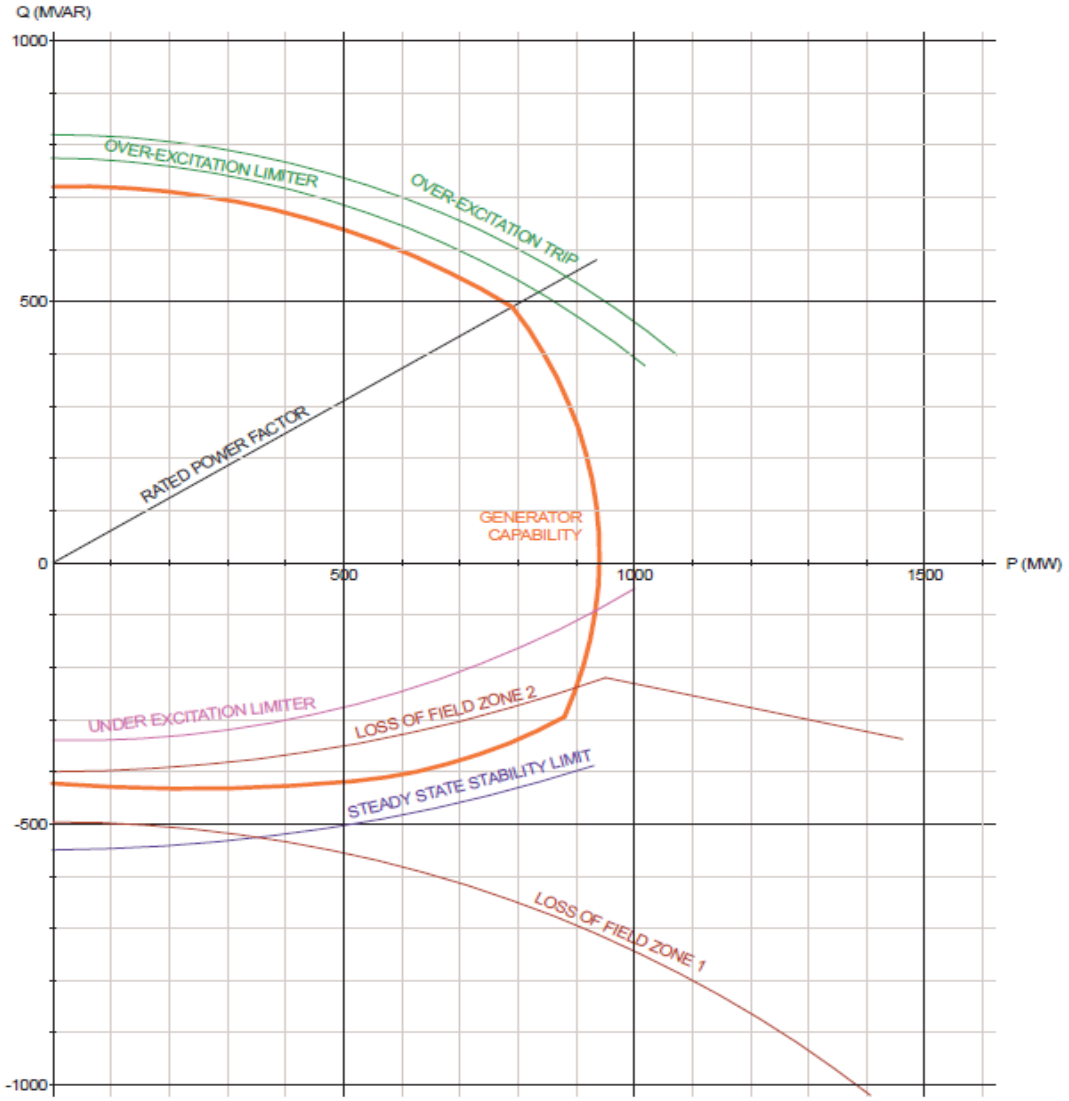
$$R = V^2_g/2*(1/X_s+1/X_d)$$

On an R-X diagram using X_d as the direct axis saturated synchronous reactance of the generator, and X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer the SSSL is an arc with the center on the X axis with the center and radius described by the following equations:

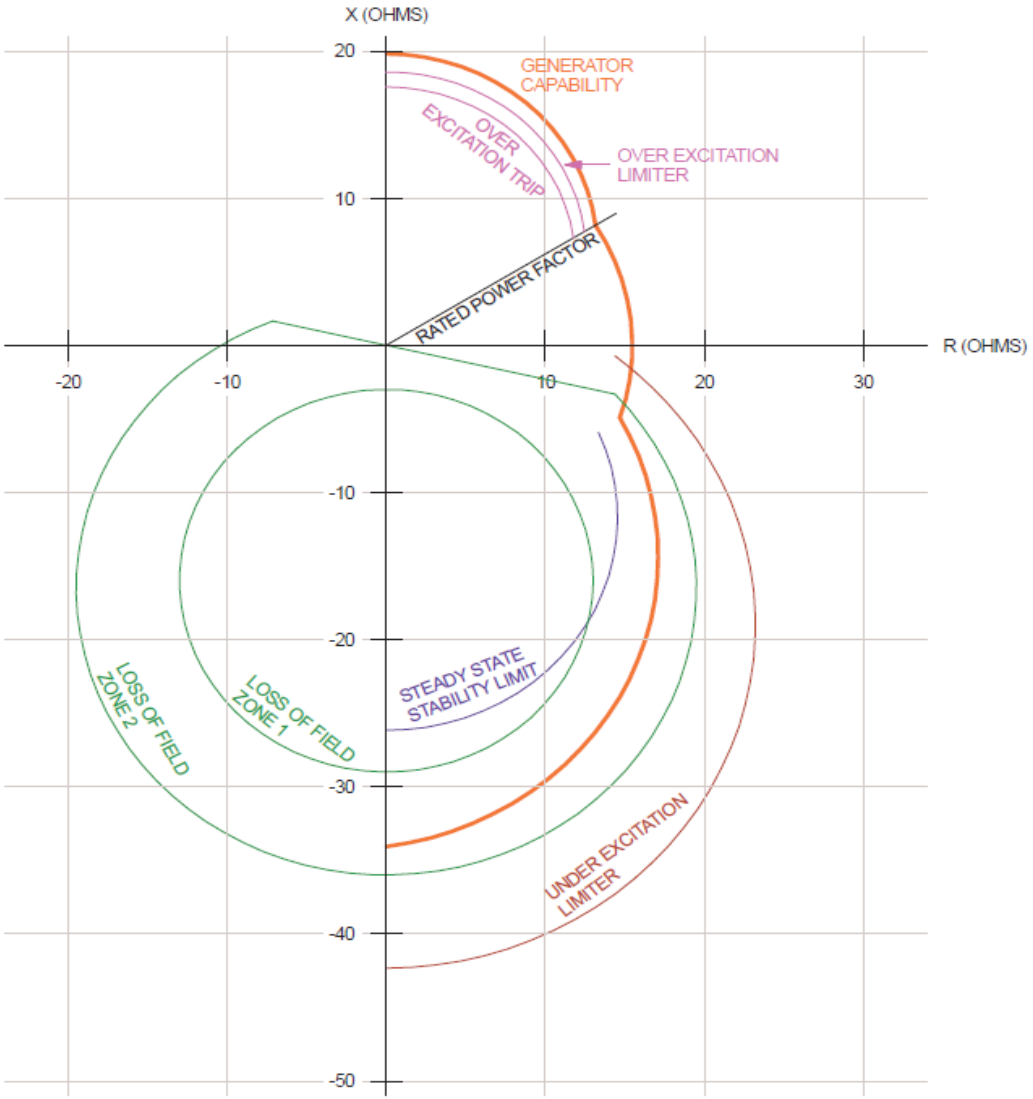
$$C = (X_d-X_s)/2$$

$$R = (X_d+X_s)/2$$

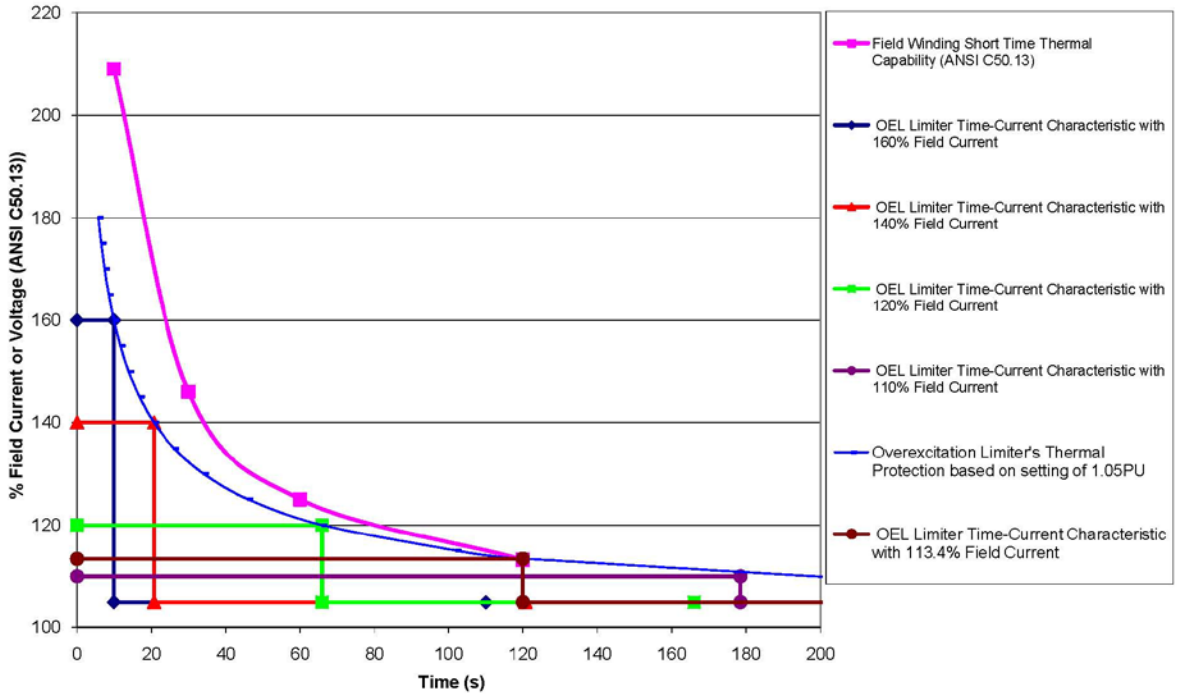
Section G Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency



Section G Attachment 2 – Example of Capabilities, Limiters, and Protection on an R-X Diagram at nominal voltage and frequency



Section G Attachment 3 - Example of Capabilities, Limiters, and Protection on an Inverse Time Characteristic Plot



Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.

Description of Current Draft

PRC-019-2 is proposed for approval to align the applicability section of PRC-019-1 with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 – Standards Applicability for Dispersed Generation Resources standards drafting team has recommended revisions to the Facilities section to clarify that facilities that solely regulate voltage at the individual generating unit are subject to the requirements. Given the timing of concurrent standards development of PRC projects, PRC-019-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-019. If this occurs, PRC-019-2 will not go into effect. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.[1]

Anticipated Actions	Anticipated Date
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	December 2014
Final ballot	January 2015
BOT adoption	February 2015

[1] The terms “dispersed generation resources” and “dispersed power producing resources” are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

1. **Title:** Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

2. **Number:** PRC-019-21

3. **Purpose:** To verify coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings.

4. **Applicability:**

   4.1. Functional Entities

   4.1.1 Generator Owner

   4.1.2 Transmission Owner that owns synchronous condenser(s)

   4.2. Facilities

   For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following:

   4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

   4.2.2 Individual synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

   4.2.3 Generating plant/ Facility consisting of one or more units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

   4.2.3.1 This includes individual dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition where voltage regulating control for the facility is performed solely at the individual resources.

Rationale for Facilities section 4.2.3.1

For those dispersed power producing facilities that only perform voltage regulating control at the individual unit level, the SDT believes that coordination should take place at the individual power producing resource level. These facilities need to consider the Protection Systems at the individual units and their compatibility with the reactive and voltage limitations of the units. Where voltage regulating control is done at an aggregate level, applicability is already included under Facilities section 4.2.3.

4.2.4 Any generator, regardless of size, that is a blackstart unit material to and designated as part of a Transmission Operator's restoration plan.

5. Effective Date:

See the Implementation Plan for this standard.

~~**5.1.** In those jurisdictions where regulatory approval is required:~~

~~**5.1.1** By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.~~

~~**5.1.2** By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.~~

~~**5.1.3** By the first day of the first calendar quarter, four calendar years following applicable regulatory, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, approval each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.~~

~~**5.1.4** By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.~~

~~**5.2.** In those jurisdictions where regulatory approval is not required:~~

~~**5.2.1** By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.~~

~~**5.2.2** By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.~~

~~**5.2.3** By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator~~

~~Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.~~

~~5.2.4 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.~~

B. Requirements

R1. At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls, (including in-service[2] limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Assuming the normal automatic voltage regulator control loop and steady-state system operating conditions, verify the following coordination items for each applicable Facility:

1.1.1. The in-service limiters are set to operate before the Protection System of the applicable Facility in order to avoid disconnecting the generator unnecessarily.

1.1.2. The applicable in-service Protection System devices are set to operate to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits.

R2. Within 90 calendar days following the identification or implementation of systems, equipment or setting changes that will affect the coordination described in Requirement R1, each Generator Owner and Transmission Owner with applicable Facilities shall perform the coordination as described in Requirement R1. These possible systems, equipment or settings changes include, but are not limited to the following *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

- Voltage regulating settings or equipment changes;
- Protection System settings or component changes;
- Generating or synchronous condenser equipment capability changes; or
- Generator or synchronous condenser step-up transformer changes.

C. Measures

[2] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

M1. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence (such as examples provided in PRC-019 Section G) that it coordinated the voltage regulating system controls, including in-service[3] limiters and protection functions, with the applicable equipment capabilities and settings of the applicable Protection System devices and functions as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed.

M2. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence of the coordination required by the events listed in Requirement R2. This evidence should include dated documentation that demonstrates the specified intervals in Requirement R2 have been met.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention

The following evidence retention periods identify a period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention specified below is shorter than the time since the last compliance audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Owner shall retain evidence of compliance with Requirements R1 and R2, Measures M1 and M2 for six years.

If a Generator Owner or Transmission Owner is found non-compliant, the entity shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last periodic audit report and all requested and submitted subsequent audit records.

[3] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years but less than or equal to 5 calendar years plus 4 months after the previous coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years plus 4 months but less than or equal to 5 calendar years plus 8 months after the previous coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years plus 8 months but less than or equal to 5 calendar years plus 12 months after the previous coordination.	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 5 calendar years plus 12 months after the previous coordination.
R2	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 90 calendar days but less than or equal to 100 calendar days following the identification or implementation of a change in equipment	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 100 calendar days but less than or equal to 110 calendar days following the identification or implementation of a change in equipment	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 110 calendar days but less than or equal to 120 calendar days following the identification or implementation of a change in equipment	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 120 calendar days following the identification or implementation of a change in equipment or settings that

	or settings that affected the coordination.	or settings that affected the coordination.	or settings that affected the coordination.	affected the coordination.

E. Regional Variances

None.

F. Associated Documents

"Underexcited Operation of Turbo Generators", AIEE Proceedings T Section 881, Volume 67, 1948, Appendix 1, C. G. Adams and J. B. McClure.

,"Protective Relaying For Power Generation Systems", Boca Raton, FL, Taylor & Francis, 2006, Reimert, Donald

"Coordination of Generator Protection with Generator Excitation Control and Generator Capability", a report of Working Group J5 of the IEEE PSRC Rotating Machinery Subcommittee

"IEEE C37.102-2006 IEEE Guide for AC Generator Protection"

"IEEE C50.13-2005 IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above"

Version History

Version	Date	Action	Change Tracking
1	February 7, 2013	Adopted by NERC Board of Trustees	New
1	March 20, 2014	FERC Order issued approving PRC-019-1. (Order becomes effective on 7/1/16.)	

G. Reference

Examples of Coordination

The evidence of coordination associated with Requirement R1 may be in the form of:

- P-Q Diagram (Example in Attachment 1), or
- R-X Diagram (Example in Attachment 2), or

- Inverse Time Diagram (Example in Attachment 3) or,
- Equivalent tables or other evidence

This evidence should include the equipment capabilities and the operating region for the limiters and protection functions

Equipment limits, types of limiters and protection functions which could be coordinated include (but are not limited to):

- Field over-excitation limiter and associated protection functions.
- Inverter over current limit and associated protection functions.
- Field under-excitation limiter and associated protection functions.
- Generator or synchronous condenser reactive capabilities.
- Volts per hertz limiter and associated protection functions.
- Stator over-voltage protection system settings.
- Generator and transformer volts per hertz capability.
- Time vs. field current or time vs. stator current.

NOTE: This listing is for reference only. This standard does not require the installation or activation of any of the above limiter or protection functions.

For this example, the Steady State Stability Limit (SSSL) is the limit to synchronous stability in the under-excited region with fixed field current.

On a P-Q diagram using X_d as the direct axis saturated synchronous reactance of the generator, X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer and V_g as the generator terminal voltage (all values in per-unit), the SSSL can be calculated as an arc with the center on the Q axis with the magnitude of the center and radius described by the following equations

$$C = V^2_g/2*(1/X_s-1/X_d)$$

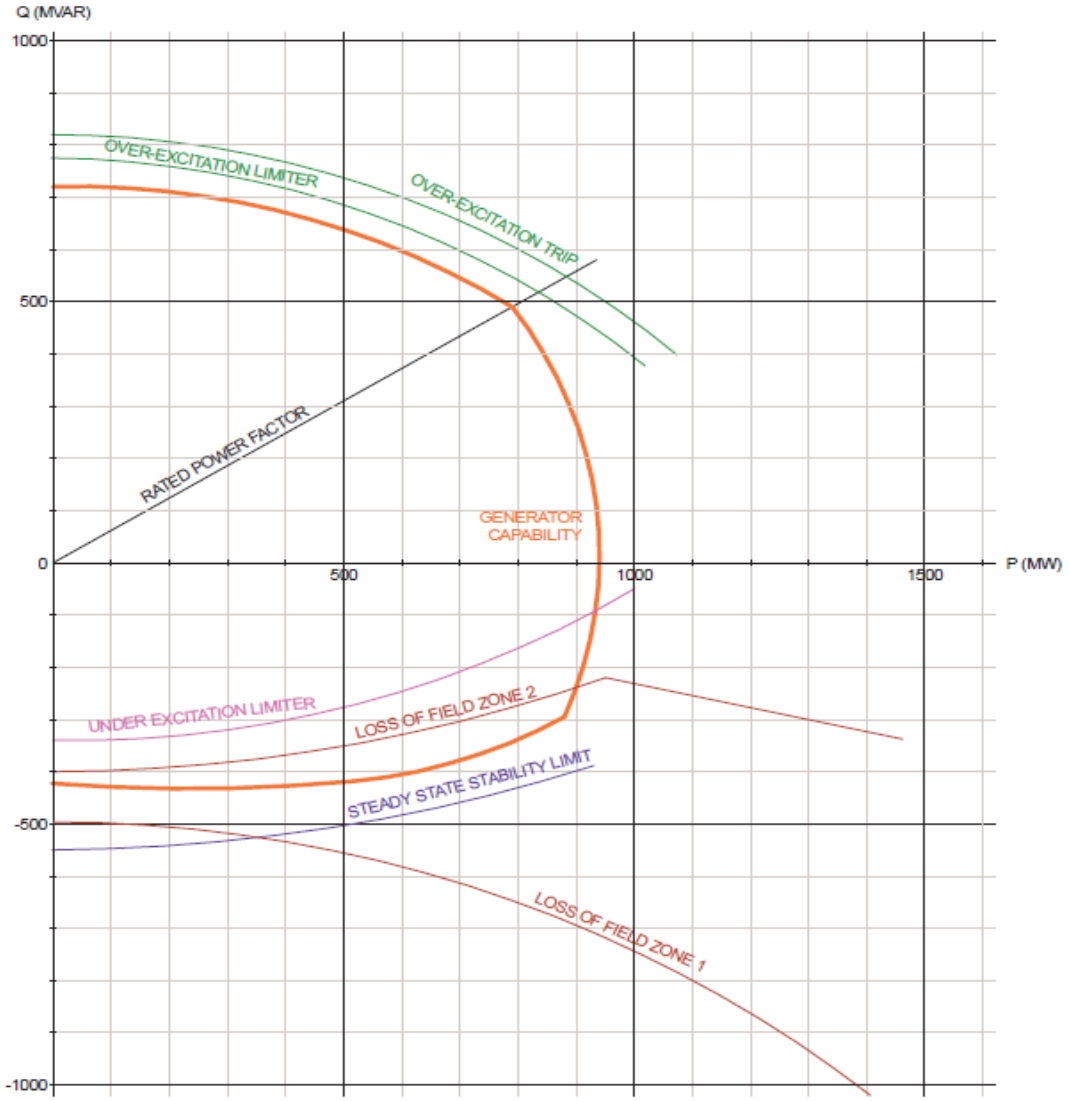
$$R = V^2_g/2*(1/X_s+1/X_d)$$

On an R-X diagram using X_d as the direct axis saturated synchronous reactance of the generator, and X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer the SSSL is an arc with the center on the X axis with the center and radius described by the following equations:

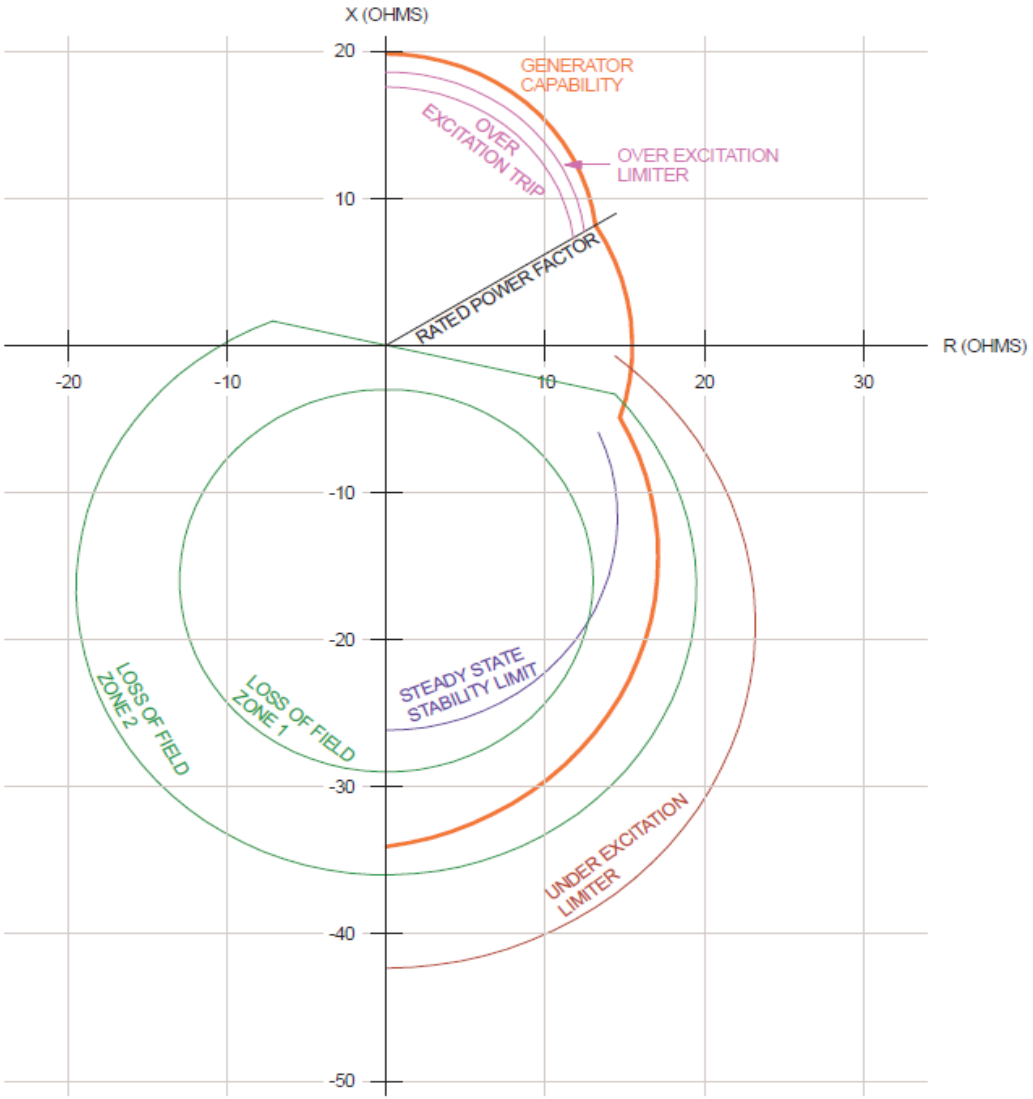
$$C = (X_d - X_s)/2$$

$$R = (X_d + X_s)/2$$

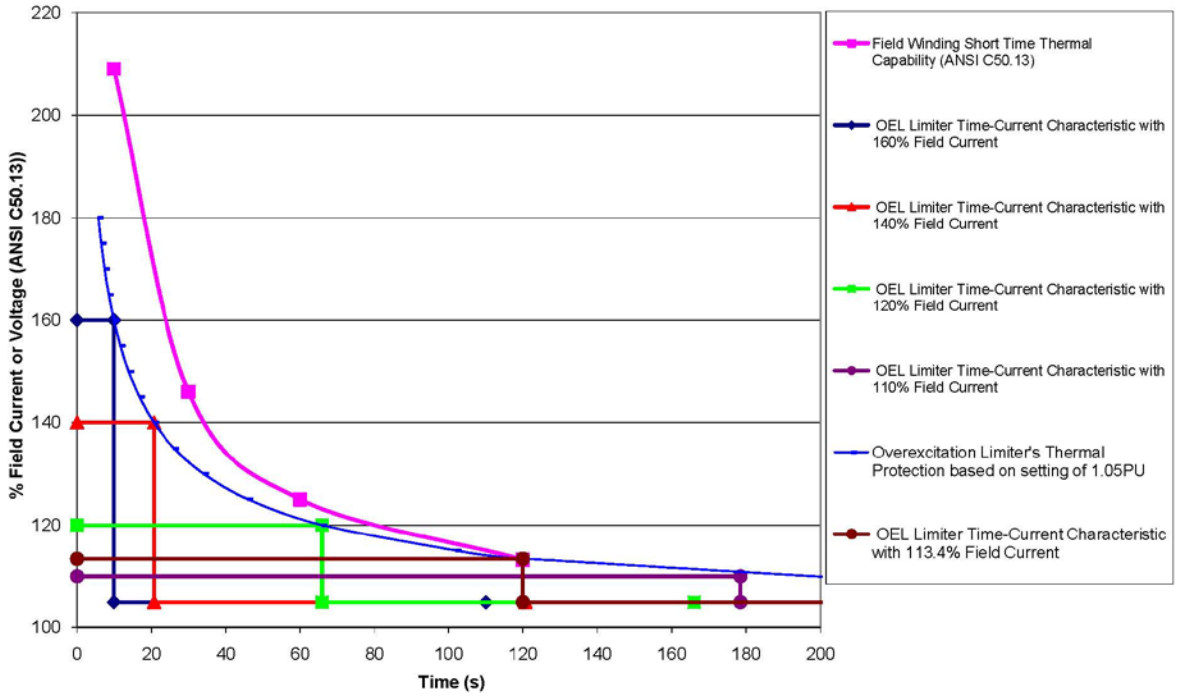
Section G Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency



Section G Attachment 2 – Example of Capabilities, Limiters, and Protection on an R-X Diagram at nominal voltage and frequency



Section G Attachment 3 - Example of Capabilities, Limiters, and Protection on an Inverse Time Characteristic Plot



Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.

Description of Current Draft

PRC-024-1(X)[1] is proposed for approval to align the applicability section of PRC-024-1 with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 –Standards Applicability for Dispersed Generation Resources standards drafting team recommended changes to the requirements addressing the scope of applicability and also recommended changes to the Reliability Standard Audit Worksheet to address documentation options. Given the timing of concurrent standards development of PRC projects, PRC-024-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-024. If this occurs, PRC-024-1(X) will not go into effect. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.[2]

Anticipated Actions	Anticipated Date
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	December 2014
Final ballot	January 2015
BOT adoption	February 2015

[1] The standard version number currently includes an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to adoption by the NERC Board of Trustees.

[2] The terms “dispersed generation resources” and “dispersed power producing resources” are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

1. **Title:** Generator Frequency and Voltage Protective Relay Settings

2. **Number: PRC-024-1(X)**

3. **Purpose:** Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.

4. **Applicability:**

   4.1. Generator Owner

5. **Effective Date:**

   See the Implementation Plan for this standard.

B. Requirements

R1. Each Generator Owner that has generator frequency protective relaying[3] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the "no trip zone" of PRC-024 Attachment 1, subject to the following exceptions:[4] *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

[3] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

[4] For frequency protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to frequency protective relays applied on the individual power producing resources, as well as frequency protective relays applied on equipment from the individual power producing resource up to the point of interconnection.

Rationale for Footnotes 2 and 4

The SDT has determined it is appropriate to require that protective relay settings applied on both the individual generating units and aggregating equipment (including any non-Bulk Electric System collection system equipment) are set within the "no-trip zone" referenced in the requirements to maintain reliability of the BES. If any of the protective relay settings applied on these elements of the facility were to be excluded from this standard, the potential would exist for portions of or the entire generating capacity of the dispersed power producing facility to be lost during a voltage or frequency excursion.

R2. Each Generator Owner that has generator voltage protective relaying[3] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection[5]) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2.[6] If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner's study. Requirement R2 is subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

[5] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

[6] For voltage protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to voltage protective relays applied on the individual power producing resources, as well as voltage protective relays applied on equipment from the individual power producing resource up to the point of interconnection.

R3. Each Generator Owner shall document each known regulatory or equipment limitation[7] that prevents an applicable generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:

- Identification of a regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.
- Replacement of the equipment causing the limitation with equipment that removes the limitation.
- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.

R4. Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets or other documentation.

M2. Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, dynamic simulation studies or other documentation.

M3. Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.

[7] Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.

M4. Each Generator Owner shall have evidence that it communicated applicable generator protective relay trip settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases, the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner shall retain evidence of compliance with Requirement R1 through R4; for 3 years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, the Generator Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generating unit, failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit, failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	OR The Generator Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.
R4	The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner failed to provide its generator protection trip settings within 150 calendar days of any change to those trip settings. OR The Generator Owner failed to provide trip settings within 150 calendar days of a written request.

E. Regional Variances

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
1	May 9, 2013	Adopted by the NERC Board of Trustees	

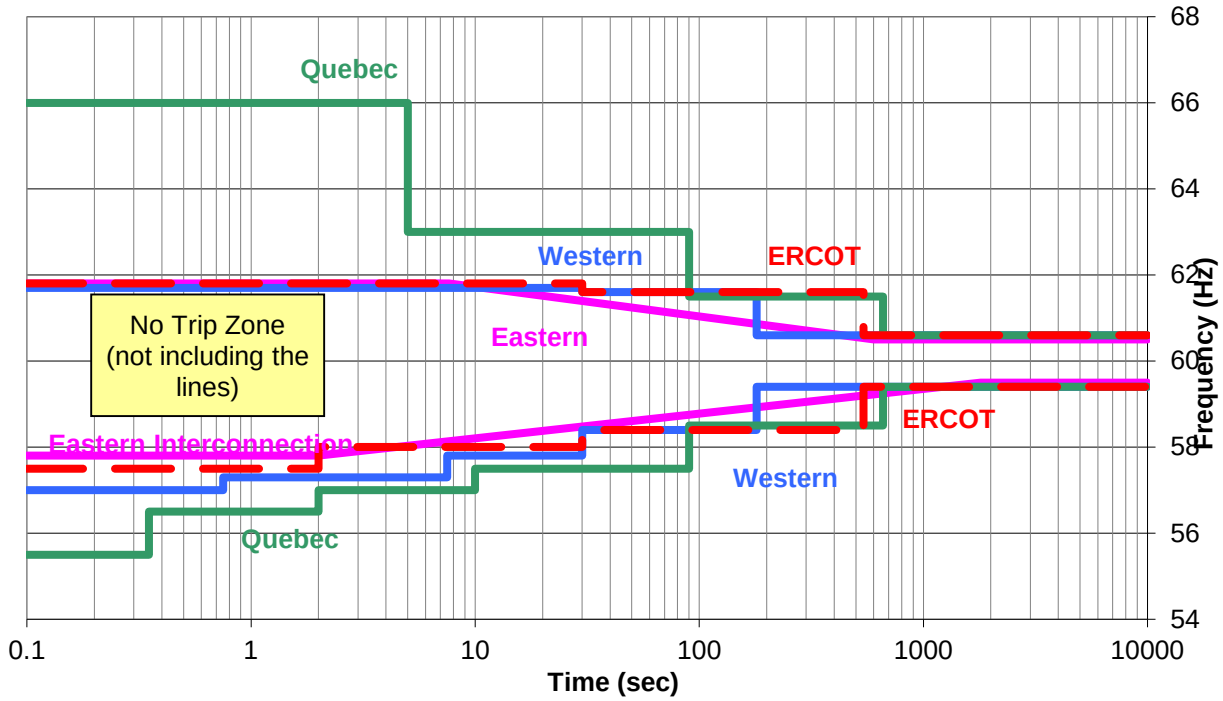
1	March 20, 2014	FERC Order issued approving PRC-024-1. (Order becomes effective on 7/1/16.)	

G. References

1. "The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF)," dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

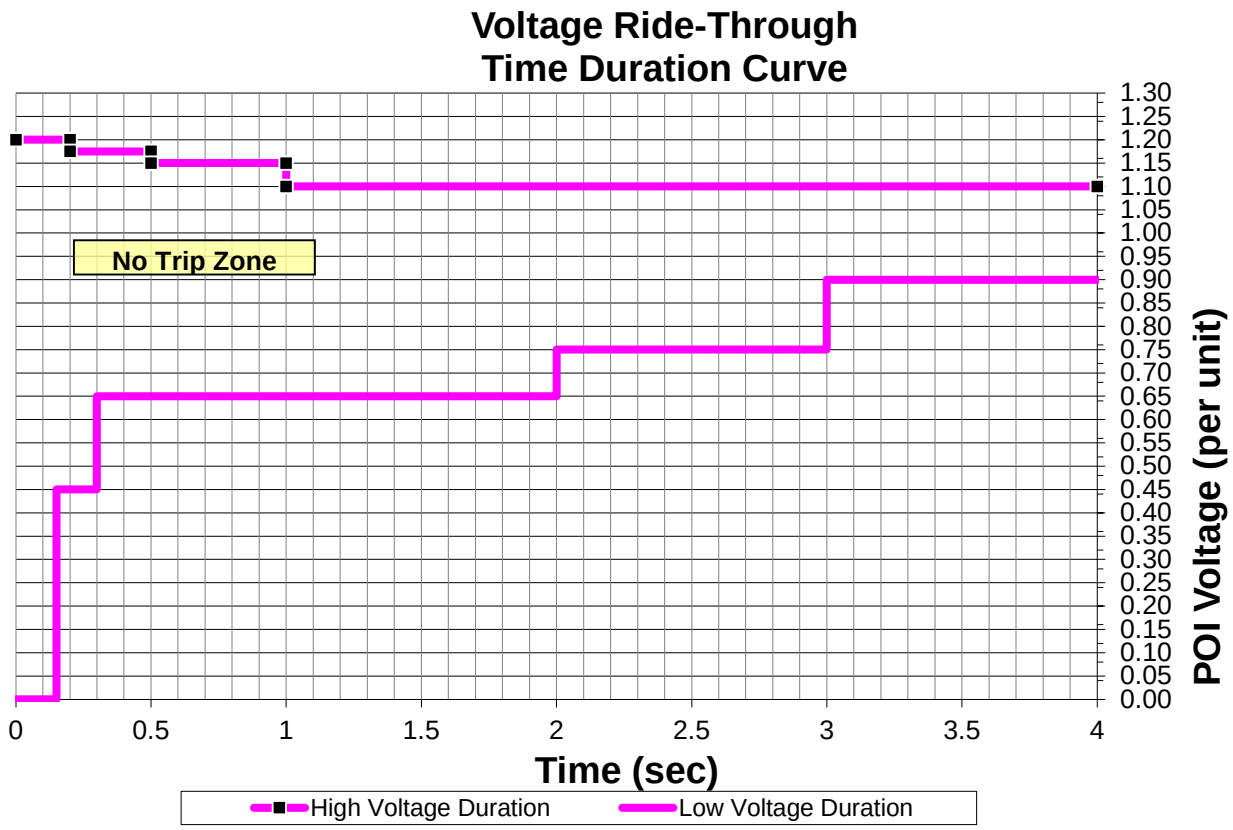
Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (Sec)
>66.0	Instantaneous trip	<55.5	Instantaneous trip
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.5	Instantaneous trip
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024— Attachment 2



Ride Through Duration:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	Time (sec)	Voltage (pu)	Time (sec)
≥1.200	Instantaneous trip	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
    a. All of the units connected to the same transformer are online and operating.
    b. All of the units are at full nameplate real-power output.
    c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
    d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.

Description of Current Draft

PRC-024-1(X)[1] is proposed for approval to align the applicability section of PRC-024-1 with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 –Standards Applicability for Dispersed Generation Resources standards drafting team recommended changes to the requirements addressing the scope of applicability and also recommended changes to the Reliability Standard Audit Worksheet to address documentation options. Given the timing of concurrent standards development of PRC projects, PRC-024-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-024. If this occurs, PRC-024-1(X) will not go into effect. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.[2]

Anticipated Actions	Anticipated Date
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	December 2014
Final ballot	January 2015
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[1] The standard version number currently includes an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to adoption by the NERC Board of Trustees.

[2] The terms “dispersed generation resources” and “dispersed power producing resources” are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

1. **Title:** Generator Frequency and Voltage Protective Relay Settings

2. **Number:** **PRC-024-1(X)**

3. **Purpose:** Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.

4. **Applicability:**

   4.1. Generator Owner

5. **Effective Date:**

   See the Implementation Plan for this standard.

~~In those jurisdictions where regulatory approval is required:~~

~~By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~In those jurisdictions where regulatory approval is not required:~~

~~By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

B. Requirements

R1. Each Generator Owner that has generator frequency protective relaying[3] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the "no trip zone" of PRC-024 Attachment 1, subject to the following exceptions:[4] *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

Rationale for Footnotes 2 and 4

The SDT has determined it is appropriate to require that protective relay settings applied on both the individual generating units and aggregating equipment (including any non-Bulk Electric System collection system equipment) are set within the "no-trip zone" referenced in the requirements to maintain reliability of the BES. If any of the protective relay settings applied on these elements of the facility were to be excluded from this standard, the potential would exist for portions of or the entire generating capacity of the dispersed power producing facility to be lost during a voltage or frequency excursion.

R2. Each Generator Owner that has generator voltage protective relaying[3] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection[5]) caused by an event on the

[3] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

[4] For frequency protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to frequency protective relays applied on the individual power producing resources, as well as frequency protective relays applied on equipment from the individual power producing resource up to the point of interconnection.

[5] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2.[6] If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner's study. Requirement R2 is subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

R3. Each Generator Owner shall document each known regulatory or equipment limitation[7] that prevents an applicable generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:

- Identification of a regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.
- Replacement of the equipment causing the limitation with equipment that removes the limitation.
- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.

[6] For voltage protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to voltage protective relays applied on the individual power producing resources, as well as voltage protective relays applied on equipment from the individual power producing resource up to the point of interconnection.

[7] Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.

R4. Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets or other documentation.

M2. Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, dynamic simulation studies or other documentation.

M3. Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.

M4. Each Generator Owner shall have evidence that it communicated applicable generator protective relay trip settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases, the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner shall retain evidence of compliance with Requirement R1 through R4; for 3 years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, the Generator Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generating unit, failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit, failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	OR The Generator Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.
R4	The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner failed to provide its generator protection trip settings within 150 calendar days of any change to those trip settings. OR The Generator Owner failed to provide trip settings within 150 calendar days of a written request.

E. Regional Variances

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
1	May 9, 2013	Adopted by the NERC Board of Trustees	

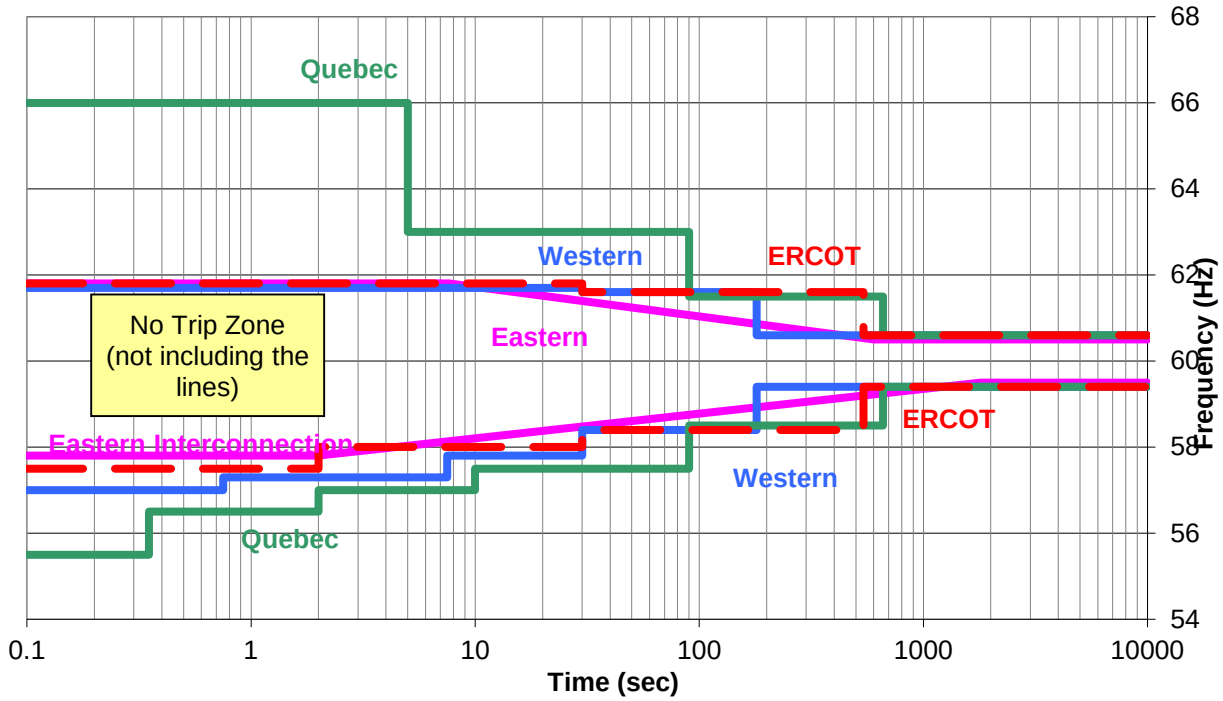
1	March 20, 2014	FERC Order issued approving PRC-024-1. (Order becomes effective on 7/1/16.)	

G. References

1. "The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF)," dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

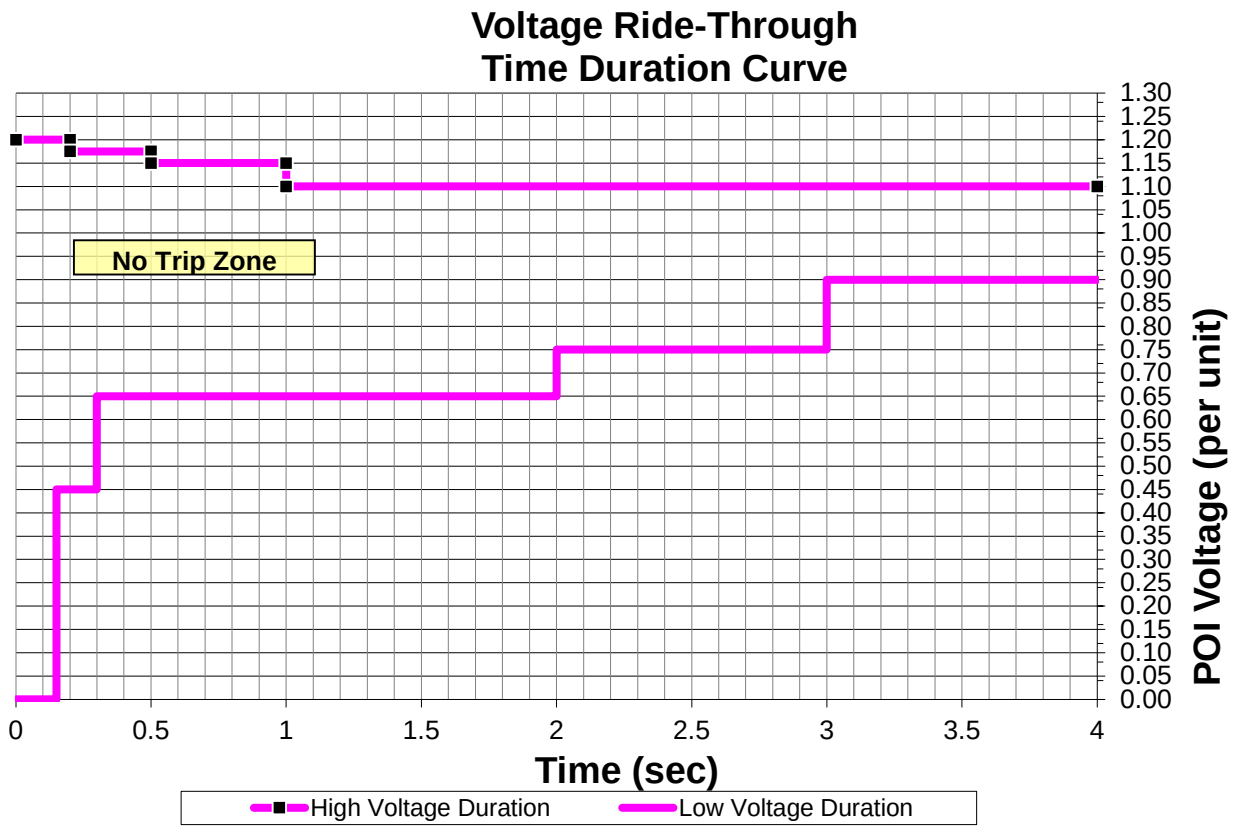
Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (Sec)
>66.0	Instantaneous trip	<55.5	Instantaneous trip
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.5	Instantaneous trip
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024— Attachment 2



Ride Through Duration:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	**Time (sec)**	**Voltage (pu)**	**Time (sec)**
≥1.200	Instantaneous trip	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
    a. All of the units connected to the same transformer are online and operating.
    b. All of the units are at full nameplate real-power output.
    c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
    d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

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Implementation Plan

Dispersed Generation Resources
PRC-001-1.1(X)

The standard version number currently include an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to adoption by the NERC Board of Trustees.

Standards Involved

Approval:

- PRC-001-1.1(X) – System Protection Coordination

Retirement:

- PRC-001-1.1a – System Protection Coordination

Prerequisite Approvals:

N/A

Background

In light of the adoption of a revised Bulk Electric System (BES) definition by the NERC Board of Trustees, changes to the applicability of certain Reliability Standards, including PRC-001, are necessary to align the standards with the implementation of the revised BES definition. The standard drafting team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Generation Resources has modified the applicability section and requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed power producing resources in order to ensure the applicability of the standards is consistent with the reliable operation of the BES.[1]

General Considerations

PRC-001-1.1(X) is proposed for approval to align the applicability of PRC-001-1.1a with the revised definition of the BES. Specifically, the SDT has coordinated with the other SDTs currently reviewing this standard and has recommended revisions to Requirement R3.1 to account for the unique characteristics of dispersed power producing resources. Given the timing of concurrent standards development of PRC, TRP, and IRO projects, PRC-001-1.1a may be retired pursuant to an Implementation Plan of a successor version of PRC-001. If this occurs, PRC-001-1.1(X) will not go into effect.

Effective Date

PRC-001-1.1(X) shall become effective immediately after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable

[1] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

The existing standard, PRC-001-1.1a, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-001-1.1(X).

Applicability:

This standard applies to the following functional entities:

- Transmission Operator
- Generator Operator
- Balancing Authority

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Implementation Plan

Dispersed Generation Resources
PRC-019-2

Standards Involved

Approval:

- PRC-019-2 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Retirement:

- PRC-019-1 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Prerequisite Approvals:

N/A

Background

In light of the adoption of a revised Bulk Electric System (BES) definition by the NERC Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-019, are necessary to align the standards with the implementation of the revised BES definition. The standard drafting team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Generation Resources has modified the applicability section and requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed power producing resources in order to ensure the applicability of the standards is consistent with the reliable operation of the BES.[1]

General Considerations

PRC-019-2 is proposed for approval to align the applicability section of PRC-019-1 with the revised definition of the BES. Specifically, the SDT has recommended revisions to the Facilities section to clarify that facilities that solely regulate voltage at the individual generating unit are subject to the requirements. Given the timing of concurrent standards development of PRC projects, PRC-019-1 may already be retired pursuant to an Implementation Plan of a successor version of PRC-. If this occurs, PRC-019-2 will not go into effect.

[1] The terms “dispersed generation resources” and “dispersed power producing resources” are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

Effective Date

PRC-019-2 shall become effective immediately after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

The existing standard, PRC-019-1, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-019-2

Applicability:

This standard applies to the following functional entities:

- Transmission Owner that owns synchronous condenser(s)
- Generator Owner

Implementation Plan

All aspects of the Implementation Plan for PRC-019-1 will remain applicable to PRC-019-2 and are incorporated here by reference.

Cross References

The Implementation Plan for the revised definition of "Bulk Electric System" is available here.

The Implementation Plan for PRC-019-1 is available here.

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Implementation Plan

Dispersed Generation Resources
PRC-024-1(X)

The standard version numbers currently include an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to adoption by the NERC Board of Trustees.

Standards Involved

Approval:

- PRC-024-1(X) – Generator Frequency and Voltage Protective Relay Settings

Retirement:

- PRC-024-1 – Generator Frequency and Voltage Protective Relay Settings

Prerequisite Approvals:

N/A

Background

In light of the adoption of a revised Bulk Electric System (BES) definition by the NERC Board of Trustees, changes to the applicability of certain Reliability Standards, including PRC-024, are necessary to align the standards with the revised BES definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Generation Resources has modified the applicability section or requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the BES.

General Considerations

PRC-024-1(X) is proposed for approval to align the applicability of PRC-024-1 with the revised definition of the BES. Specifically, the SDT recommended changes to the requirements addressing the scope of applicability and also recommended changes to the Reliability Standard Audit Worksheet to address documentation options. Given the timing of concurrent standards development of PRC projects, PRC-024-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-024. If this occurs, PRC-024-1(X) will not go into effect.

Effective Date

PRC-024-1(X) shall become effective immediately after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first

calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:
The existing standard, PRC-024-1, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-024-1(X).

Applicability:
This standard applies to the following functional entities:

- Generator Owner

Implementation Plan
All aspects of the Implementation Plan for PRC-024-1 will remain applicable to PRC-024-(X) and are incorporated here by reference.

Cross References
The Implementation Plan for the revised definition of "Bulk Electric System" is available here.

The Implementation Plan for PRC-024-1 is available here.

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Unofficial Comment Form

Project 2014-01 Standards Applicability for Dispersed Generation Resources

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standards. The electronic comment form must be completed by **December 19, 2014**.

If you have questions please contact Katherine Street or by telephone at 404.446.9702.

All documents for this project are available on the project page.

Background Information

This posting solicits formal comments on the three Project 2014-01 Standards Applicability for Dispersed Generation Resources (DGR) medium-priority Reliability Standards, as identified in the draft White Paper prepared by the Project 2014-01 (Project) standards drafting team (DGR SDT).

The goal of the Project is to ensure that Generator Owners (GOs) and Generator Operators (GOPs) of dispersed power producing resources[1] are appropriately assigned responsibility for requirements that impact the reliability of the Bulk Power System, as the characteristics of operating dispersed power producing resources can be unique. In light of the revised Bulk Electric System (BES) definition approved by the Federal Energy Regulatory Commission in 2014, the intent of this Project is generally to maintain the status quo for applicability of the standards as they have been applied over time with respect to dispersed power producing resources where the status quo does not create a reliability gap.

The DGR SDT reviewed all standards that apply to GOs and GOPs and categorized how each standard should be applied to dispersed power producing resources to accomplish the reliability purpose of the standard. The DGR SDT developed the White Paper to explain its approach, which was posted on April 17, 2014 for an informal comment period.[2] Industry feedback on the White Paper allowed the DGR SDT to refine its approach and finalize recommended revisions to the standards. As part of this review, the DGR SDT determined that there are three medium-priority standards in which attention is required:

- PRC-001-1.1;
- PRC-019-2; and
- PRC-024-1.

Because two of the medium-priority standards have recently been revised or are undergoing revision in another current project, the DGR SDT has developed revisions to allow for different possibilities in the

[1] The terms dispersed generation resources and dispersed power producing resources are used interchangeably.
[2] The current version of the White Paper can be downloaded on the Project web page at http://www.nerc.com/pa/Stand/Pages/Project-2014-01-Standards-Applicability-for-Dispersed-Generation-Resources.aspx.

timing of regulatory approvals. When the revisions are being applied to a version that is not the last approved version of the standard or to a version that is pending regulatory approval, the version is noted with "(X)" after it. Please note that any versions of the standards posted under this project with an "X" suffix will have a version number applied at a later time in order to manage sequencing of version numbers. Please also note that NERC has recently developed a version numbering convention that dictates a different suffix, but since the subject standards were approved by the NERC Standards Committee with the "X" suffix, that convention is maintained here to avoid confusion. The intent of balloting the recommended applicability revisions separately from the technical changes that are ongoing in other projects is to provide flexibility to allow approved applicability revisions to move forward on an expedited timeline as needed to support implementation of the revised definition of the BES.

Summary of Proposed Changes

The DGR SDT's recommended changes are limited to revising the applicability of the relevant versions of PRC-001-1.1, PRC-019-2, and PRC-024-1 to appropriately account for certain dispersed power producing resources.

The DGR SDT has posted the following standards, along with corresponding Implementation Plans:

- PRC-001-1.1(X) (clean and redlined to PRC-001-1.1)
- PRC-019-2 (clean and redlined to PRC-0019-1)
- PRC-024-1(X) (clean and redlined to PRC-024-1)
- SAR

Please note that the DGR SDT has not revised the Violation Risk Factors (VRFs) or Violation Severity Levels (VSLs) associated with the medium-priority standards because the proposed revisions do not change the reliability intent or impact any of the requirements. If the applicability recommendations are approved by industry as proposed, the DGR SDT would not seek to change the VRFs and.

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Questions

1. Do you agree with the revisions proposed in PRC-001-1.1(X) Requirement R3 part 3.1 to exclude the individual generating units of dispersed power producing resources identified through Inclusion I4 of the BES definition from this requirement? If not, please provide technical rationale for your disagreement, along with suggested language changes.

   Yes:

   No:

   Comments:

2. Do you agree with the revisions proposed in the Facilities section of proposed PRC-019-2 to clarify that the standard is applicable to dispersed power producing resources identified through Inclusion I4 of the BES definition where voltage regulating control for the facility is performed solely at the individual resource? If not, please provide technical rationale for your disagreement, along with suggested language changes.

   Yes:

   No:

   Comments:

3. Do you agree with the revisions proposed in PRC-024-1(X) to clarify (via footnotes 4 and 6) that Requirements R1 and R2 are applicable to both dispersed power producing resources identified through Inclusion I4 of the BES definition, as well as any aggregating equipment (potentially including non-BES equipment) from the individual resource up to the point of interconnection? If not, please provide technical rationale for your disagreement, along with suggested language changes.

   Yes:

   No:

   Comments:

4. Do you have any additional comments to assist the DGR SDT in further developing its recommendations?

   Yes:

   No:

   Comments:

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Standards Authorization Request Form

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

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

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Application of certain GO/GOP Reliability Standards and Requirements to Dispersed Generation		
Date Submitted:	10/1/2013		
SAR Requester Information			
Name:	Jennifer Sterling-Exelon, Gary Kruempel-MidAmerican, Allen Schriver-NextEra Energy, Inc., Brian Evans-Mongeon-Utility Services Inc.		
Organization:	Exelon, MidAmerican, NextEra Energy, Utility Services Inc.		
Telephone:	(630) 437-2764 – primary contact	E-mail:	jennifer.sterling@exeloncorp.com primary contact
SAR Type (Check as many as applicable)			
☐ New Standard ☒ Revision to existing Standard		☐ Withdrawal of existing Standard ☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
The industry is requesting that the application section of certain GO/GOP Reliability Standards or the requirements of certain GO/GOP Reliability Standards be revised in order to ensure that the Reliability Standards are not imposing requirements on dispersed generation that are unnecessary and/or counterproductive to the reliable operation of the Bulk Electric System (BES). For purposes of this SAR, dispersed generation are those resources that aggregate to a total capacity greater than 75 MVA (gross

SAR Information
nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. This request is related to the proposed new definition of the Bulk Electric System (BES) from Project 2010-17, that results in the identification of elements of new dispersed generation facilities that if included under certain Reliability Standards may result in a detriment to reliability or be technically unsound and not useful to the support of the reliable operation of the BES .
Purpose or Goal (How does this request propose to address the problem described above?):
The goal of the request is to revise the applicability of GO/GOP Reliability Standards or the Requirement(s) of GO/GOP Reliability Standards to recognize the unique technical and reliability aspects of dispersed generation, given the proposed new definition of the BES.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objective of the revisions to the applicability section and/or Requirements of certain GO/GOP Reliability Standards is to ensure that these revisions are approved by the Board of Trustees and applicable regulatory agencies prior to the effective date for newly identified elements under the proposed BES definition (i.e., June 2016).
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The scope of this SAR involves revisions to the applicability section of the following GO/GOP Reliability Standard applicability sections and/or Reliability Standard Requirements: (a) PRC-005-2 (-3); (b) FAC-008-3; (c) PRC-023-3/PRC-025-1; (d) PRC-004-2a (-3) ; and (e) VAR-002-2 so it is clear what, if any, requirements should apply to dispersed generation. Also, IRO,MOD, PRC or TOP Standards that require outage and protection and control coordination, planning, next day study or real time data or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities and reporting are conducted at the point of aggregation to 75 MVA, and not at an individual turbine, inverter or unit level for dispersed generation. This scope would also include development of a technical guidance paper for standard drafting teams developing new or revised Standards, so that they do not incorrectly apply requirements to dispersed generation unless such an application is technically sound and promotes the reliable operation of the BES. To the extent, there are existing Reliability Standard Drafting Teams that have the expertise and can make the requested changes prior to the compliance date of newly identified assets under the BES definition (i.e., June 2016), those projects may be assigned the required changes as opposed to creating new projects.

SAR Information
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

The following description and technical justification(including an assessment of reliability impacts) is provided for the standard drafting teams to execute the SAR for each applicable Standard.

PRC-005-2

Testing and maintenance of protection and control equipment for dispersed generation should start at the point of aggregation to 75 MVA. Manufacturers of dispersed generation turbines and solar panels recommend against specific testing and maintenance regimes for protection and control equipment at the dispersed generation turbine and panel level. In fact it is counterproductive to implement protection and control at the individual turbine, solar panel, or unit level. Instead this is best done at an aggregated level. Therefore, PRC-005 should indicate that the standard applies at the point of aggregation to at 75 MVA or greater for dispersed generation. This change would clarify that the facility section 4.2.5.3 is the section that would apply to dispersed generating facilities and that the remaining sections would not apply.

FAC-008-3

For dispersed generation, it is unclear if in FAC-008-3 the term “main step up transformer” refers to the padmount transformer at the base of the windmill tower or to the main aggregating transformer that steps up voltage to transmission system voltage. From a technical standpoint, it should be the point of aggregation at 75 MVA or above that is subject to this standard for dispersed generation, such as wind. It is at the point of aggregation at 75 MVA or above that facilities ratings should start, since it is this injection point at which a planner or operator of the system is relying on the amount of megawatts the dispersed generation is providing with consideration of the most limiting element. To require facility ratings at for each dispersed turbine, panel or generating unit is not useful to a planner or operator of the system, and, therefore, FAC-008-3 should be revised to be clear that facility ratings start at the point of aggregation at 75 MVA or above for dispersed generation.

SAR Information

Also consider that the BES definition specifically excludes collector system equipment at less than 75 MVA from being included in the BES. Thus, those portions of the collector systems that handle less than 75 MVA are not BES "Facilities," and, therefore, need not be evaluated per R1 or R2. Given this, there seems to be no technical value to conduct facility ratings for individual dispersed generation turbines, generating units and panels.

PRC-023-3/PRC-025-1

In keeping with the registration criteria for Generator Owners as well as the proposed BES Definition, the 75MVA point of aggregation should be the starting point for application of relay loadability requirements.

PRC-004-2

There is no technical basis to claim that misoperation analysis, corrective action plan implementation and reporting for dispersed generation at the turbine, generating unit or panel level is needed for the reliable operation of the BES. Similar to the statements above, the appropriate point to require misoperation analysis, corrective action plan implementation and reporting is at the point of aggregation at 75 MVA and above.

VAR-002-2

Voltage control for some types of dispersed generating facilities is accomplished by a controller that is able to adjust either generating unit controls or discrete reactive components to provide transmission system voltage adjustment. The VAR-002 standard should be modified to allow this type of control for dispersed generation facilities under the requirements of the standard.

General review of IROs, MODs, PRCs, TOPs

IRO, MOD, PRC or TOP Standards that require outage and protection and control coordination, planning, next day study or real time data or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities are conducted at the point of aggregation at 75 MVA, and not an individual turbine, generating unit or panel level for dispersed generation. Unless this clarity is provided applicability at a finer level of granularity related to dispersed generation may be seen as required and such granularity will result in activities that have no benefit to

SAR Information
reliable operation of the BES. Furthermore applicability at a finer level of granularity will result in uneeded and ineffective collection, analysis, and reporting activities that may result in a detriment to reliability.

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

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

Reliability and Market Interface Principles		
Applicable Reliability Principles (Check all that apply).		
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.	
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.	
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.	
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.	
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.	
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.	
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.	
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.	
Does the proposed Standard comply with all of the following Market Interface Principles?		Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.		Yes

Reliability and Market Interface Principles	
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
PRC-005-2, FAC-008-3, PRC-023-3/PRC-025-1/PRC-004-2a, VAR-002-2b and various IRO, MOD, PRC and TOP Standards	See explanation under technical analysis.

Related SARs	
SAR ID	Explanation
	N/A

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

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Standards Announcement Reminder

Project 2014-01 Standards Applicability for Dispersed Generation Resources
PRC-001-1.1(X), PRC-019-2, and PRC-024-1(X)

Initial Ballots Now Open through December 22, 2014

Now Available

Initial ballots for three Project 2014-01 Standards Applicability for Dispersed Generation Resources medium-priority Reliability Standards as identified in the draft White Paper prepared by the Project 2014-01 drafting team are open through **8 p.m. Eastern on Monday, December 22, 2014.**

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their votes for the standards by clicking here.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standards and post them for an additional ballot. If the comments do not show the need for significant revisions, the standards will proceed to a final ballot.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Katherine Street, Standards Developer, or at 404-446-9702.

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Standards Announcement

Project 2014-01 Standards Applicability for Dispersed Generation Resources
PRC-001-1.1(X), PRC-019-2, and PRC-024-1(X)

Formal Comment Period Now Open through December 19, 2014

Now Available

A 45-day comment period for three Project 2014-01 Standards Applicability for Dispersed Generation Resources medium-priority Reliability Standards as identified in the draft White Paper prepared by the Project 2014-01 drafting team through **8 p.m. Eastern on Friday, December 19, 2014.**

Instructions for Commenting

Please use the electronic form to submit comments on the standards. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Instructions for Joining Ballot Pools

Ballot pools are currently being formed. Registered Ballot Body members must join the ballot pools to be eligible to cast ballots. Registered Ballot Body members may join the ballot pools here.

During the pre-ballot window, members of the ballot pools may communicate with one another by using their "ballot pool listservs." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool listservs.) The listservs for this project are:

bp-2014-01-PRC-024-1X_in@nerc.com
bp-2014-01-PRC-019-2_in@nerc.com
bp-2014-01_PRC-001-1.1X_in@nerc.com

Next Steps

Initial ballots for the standards will be conducted **December 10-19, 2014**.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Katherine Street, Standards Developer, or at 404-446-9702.

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Project 2014-01 Standards Applicability for Dispersed Generation Resources
PRC-001-1.1(X), PRC-019-2, and PRC-024-1(X)

Formal Comment Period Now Open through December 19, 2014

Now Available

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bp-2014-01-PRC-024-1X_in@nerc.com
bp-2014-01-PRC-019-2_in@nerc.com
bp-2014-01_PRC-001-1.1X_in@nerc.com

Next Steps

Initial ballots for the standards will be conducted **December 10-19, 2014**.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

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Standards Announcement

Project 2014-01 Standards Applicability for Dispersed Generation Resources
PRC-001-1.1(X), PRC-019-2, and PRC-024-1(X)

Formal Comment Period Now Open through December 19, 2014

Now Available

A 45-day comment period for three Project 2014-01 Standards Applicability for Dispersed Generation Resources medium-priority Reliability Standards as identified in the draft White Paper prepared by the Project 2014-01 drafting team through **8 p.m. Eastern on Friday, December 19, 2014.**

Instructions for Commenting

Please use the electronic form to submit comments on the standards. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

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During the pre-ballot window, members of the ballot pools may communicate with one another by using their "ballot pool listservs." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool listservs.) The listservs for this project are:

bp-2014-01-PRC-024-1X_in@nerc.com
bp-2014-01-PRC-019-2_in@nerc.com
bp-2014-01_PRC-001-1.1X_in@nerc.com

Next Steps

Initial ballots for the standards will be conducted **December 10-19, 2014**.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Katherine Street, Standards Developer, or at 404-446-9702.

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Standards Announcement

Project 2014-01 Applicability for Dispersed Resources Standards
PRC-001-1.1(X), PRC-019-2, and PRC-024-1(X)

Initial Ballot Results

Now Available

Initial ballots for three Project 2014-01 Standards Applicability for Dispersed Generation Resources medium-priority Reliability Standards as identified in the draft White Paper prepared by the Project 2014-01 drafting team concluded at **8 p.m. Eastern, Tuesday, December 23, 2014.**

The standards achieved a quorum and received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballots.

Standard	Quorum /Approval
PRC-001-1.1(X)	79.38% / 92.69%
PRC-019-2	79.72% / 93.55%
PRC-024-1(X)	79.60% / 93.67%

Background information for this project can be found on the project page.

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standards and post them for an additional ballot. If the comments do not show the need for significant revisions, the standards will proceed to a final ballot.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Katherine Street, Standards Developer, or at 404-446-9702.

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Ballot Results	
Ballot Name:	Project 2014-01-DGR-PRC-001-1.1X
Ballot Period:	12/10/2014 - 12/23/2014
Ballot Type:	Initial
Total # Votes:	281
Total Ballot Pool:	354
Quorum:	**79.38 % The Quorum has been reached**
Weighted Segment Vote:	92.69 %
Ballot Results:	**The ballot has closed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	91	1	52	0.929	4	0.071	0	15	20
2 - Segment 2	8	0.5	5	0.5	0	0	0	0	3
3 - Segment 3	82	1	54	0.982	1	0.018	0	14	13
4 - Segment 4	27	1	18	0.947	1	0.053	0	5	3
5 - Segment 5	79	1	45	0.865	7	0.135	0	10	17
6 - Segment 6	52	1	30	0.909	3	0.091	0	7	12
7 - Segment 7	1	0	0	0	0	0	0	0	1
8 - Segment 8	5	0.3	2	0.2	1	0.1	0	1	1
9 - Segment 9	3	0.2	2	0.2	0	0	0	0	1

10 - Segment 10	6	0.4	4	0.4	0	0	0	0	2
Totals	**354**	**6.4**	**212**	**5.932**	**17**	**0.468**	**0**	**52**	**73**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson		
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES POWER MARKETING)
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - PSEG - (Colorado Springs Utilities)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil		
1	Great River Energy	Gordon Pietsch		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane		
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Mike Smith	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	

1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck		
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Joseph A Smith	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group (PSEG))
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Steven C Cobb	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock		
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tacoma Power	John Merrell	Abstain	
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Steven Johnson		
1	Wind Energy Transmission Texas, LLC	Julius Horvath		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore		
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist		
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	

3	Avista Corp.	Scott J Kinney	Abstain	
3	Basin Electric Power Cooperative	Jeremy Voll	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Beaches Energy Services	Steven Lancaster	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Leesburg	Chris Adkins	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	Colorado Springs Utilities	Jean Mueller		
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer		
3	CPS Energy	Jose Escamilla		
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Abstain	
3	FirstEnergy Corp.	Richard S Hoag	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Fort Pierce Utilities Authority	Thomas Parker	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough		
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach		
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Seth Shoemaker	Affirmative	
3	N.W. Electric Power Cooperative, Inc.	John Stickley	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Abstain	
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orlando Utilities Commission	Ballard K Mutters		
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
3	Puget Sound Energy, Inc.	Andrea Basinski	Affirmative	
3	Rutherford EMC	Thomas Haire	Abstain	

3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Tacoma Power	Marc Donaldson	Abstain	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen		
4	Consumers Energy Company	Tracy Goble		
4	DTE Electric	Daniel Herring	Abstain	
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Fort Pierce Utilities Authority	Javier Cisneros	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Keys Energy Services	Stan T Rzad	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	Basin Electric Power Cooperative	Mike Kraft	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty		
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
				SUPPORTS

5	Colorado Springs Utilities	Kaleb Brimhall	Negative	THIRD PARTY COMMENTS - PSEG - (Colorado Springs Utilities)
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (William English)
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources Services	Randall C Heise	Affirmative	
5	DTE Electric	Mark Stefaniak	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	EDP Renewables North America LLC	Heather Bowden		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Abstain	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Yuguang Xiao	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Abstain	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG (John Seelke))
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	

5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Abstain	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tennessee Valley Authority	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - PSEG - (Colorado Springs Utilities)
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Abstain	
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Shivaz Chopra		
6	New York State Electric & Gas Corp.	Julie S King		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	COMMENT RECEIVED
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza		



6	Tacoma Public Utilities	Michael C Hill	Abstain	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
6	Westar Energy	Tiffany Lake	Affirmative	
6	Western Area Power Administration - UGP Marketing	Mark Messerli	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway		
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake		
8		Roger C Zaklukiewicz	Affirmative	
8		David L Kiguel	Negative	COMMENT RECEIVED
8		Debra R Warner	Abstain	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	City of Vero Beach	Ginny Beigel	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Bob Reynolds		
10	Western Electricity Coordinating Council	Steven L. Rueckert		

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Ballot Results	
Ballot Name:	Project 2014-01-DGR-PRC-019-2
Ballot Period:	12/10/2014 - 12/23/2014
Ballot Type:	Initial
Total # Votes:	283
Total Ballot Pool:	355
Quorum:	**79.72 % The Quorum has been reached**
Weighted Segment Vote:	93.55 %
Ballot Results:	**The ballot has closed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	91	1	51	0.927	4	0.073	0	18	18
2 - Segment 2	7	0.3	2	0.2	1	0.1	0	1	3
3 - Segment 3	83	1	52	0.981	1	0.019	0	16	14
4 - Segment 4	27	1	18	0.947	1	0.053	0	5	3
5 - Segment 5	79	1	48	0.906	5	0.094	0	9	17
6 - Segment 6	52	1	31	0.939	2	0.061	0	7	12
7 - Segment 7	1	0	0	0	0	0	0	0	1
8 - Segment 8	5	0.3	3	0.3	0	0	0	1	1
9 - Segment 9	3	0.2	2	0.2	0	0	0	0	1

10 - Segment 10	7	0.4	4	0.4	0	0	0	1	2
Totals	**355**	**6.2**	**211**	**5.8**	**14**	**0.4**	**0**	**58**	**72**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Negative	COMMENT RECEIVED
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson		
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES POWER MARKETING)
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil		
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch		
1	Hydro One Networks, Inc.	Muhammed Ali	Abstain	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane		
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Mike Smith	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	

1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Joseph A Smith	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Steven C Cobb	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock		
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tacoma Power	John Merrell	Abstain	
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Steven Johnson		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Negative	COMMENT RECEIVED
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore		
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist		
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Avista Corp.	Scott J Kinney	Abstain	
3	Basin Electric Power Cooperative	Jeremy Voll	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Beaches Energy Services	Steven Lancaster	Affirmative	
3	Blue Ridge Electric	James L Layton		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	

3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Leesburg	Chris Adkins	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	Colorado Springs Utilities	Jean Mueller		
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer		
3	CPS Energy	Jose Escamilla		
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion's submitted comments)
3	DTE Electric	Kent Kujala	Abstain	
3	FirstEnergy Corp.	Richard S Hoag	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Fort Pierce Utilities Authority	Thomas Parker	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough		
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Abstain	
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach		
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Seth Shoemaker	Affirmative	
3	N.W. Electric Power Cooperative, Inc.	John Stickley	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Abstain	
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orlando Utilities Commission	Ballard K Mutters		
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Andrea Basinski	Affirmative	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	

3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Tacoma Power	Marc Donaldson	Abstain	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen		
4	Consumers Energy Company	Tracy Goble		
4	DTE Electric	Daniel Herring	Abstain	
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Fort Pierce Utilities Authority	Javier Cisneros	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Keys Energy Services	Stan T Rzad	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments from AZPS)
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	Basin Electric Power Cooperative	Mike Kraft	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty		
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		

5	Dominion Resources Services	Randall C Heise	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion Submitted Comments)
5	DTE Electric	Mark Stefaniak	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	EDP Renewables North America LLC	Heather Bowden		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Yuguang Xiao	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Abstain	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Abstain	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tennessee Valley Authority	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	

6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion's submitted comments)
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Abstain	
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Shivaz Chopra		
6	New York State Electric & Gas Corp.	Julie S King		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza		
6	Tacoma Public Utilities	Michael C Hill	Abstain	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
6	Westar Energy	Tiffany Lake	Affirmative	
6	Western Area Power Administration - UGP Marketing	Mark Messerli	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway		
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake		
8		Roger C Zaklukiewicz	Affirmative	
8		David L Kiguel	Affirmative	
8		Debra R Warner	Abstain	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	City of Vero Beach	Ginny Beigel	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	



9	New York State Public Service Commission	Diane J Barney		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Bob Reynolds		
10	Texas Reliability Entity, Inc.	Derrick Davis	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert		

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Ballot Results	
Ballot Name:	Project 2014-01-DGR-PRC-024-1X
Ballot Period:	12/10/2014 - 12/23/2014
Ballot Type:	Initial
Total # Votes:	281
Total Ballot Pool:	353
Quorum:	**79.60 % The Quorum has been reached**
Weighted Segment Vote:	93.67 %
Ballot Results:	**The ballot has closed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	90	1	49	0.907	5	0.093	0	18	18
2 - Segment 2	7	0.3	3	0.3	0	0	0	1	3
3 - Segment 3	82	1	50	0.926	4	0.074	0	15	13
4 - Segment 4	27	1	19	0.95	1	0.05	0	4	3
5 - Segment 5	79	1	48	0.906	5	0.094	0	8	18
6 - Segment 6	52	1	31	0.912	3	0.088	0	6	12
7 - Segment 7	2	0.1	1	0.1	0	0	0	0	1
8 - Segment 8	5	0.3	3	0.3	0	0	0	1	1
9 - Segment 9	3	0.2	2	0.2	0	0	0	0	1

10 - Segment 10	6	0.4	4	0.4	0	0	0	0	2
Totals	**353**	**6.3**	**210**	**5.901**	**18**	**0.399**	**0**	**53**	**72**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Negative	SUPPORTS THIRD PARTY COMMENTS - (The individual generating unit of a dispersed power producing resources has negligible impact on BES)
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson		
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil		
1	Great River Energy	Gordon Pietsch		
1	Hydro One Networks, Inc.	Muhammed Ali	Abstain	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Abstain	
1	International Transmission Company Holdings Corp	Michael Moltane		
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam	Affirmative	

1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Mike Smith	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Negative	COMMENT RECEIVED
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Joseph A Smith	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Steven C Cobb	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock		
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tacoma Power	John Merrell	Negative	SUPPORTS THIRD PARTY COMMENTS - (Michael Hill)
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Steven Johnson		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung		

3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore		
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist		
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Avista Corp.	Scott J Kinney	Abstain	
3	Basin Electric Power Cooperative	Jeremy Voll	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Beaches Energy Services	Steven Lancaster	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Leesburg	Chris Adkins	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	Colorado Springs Utilities	Jean Mueller		
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer		
3	CPS Energy	Jose Escamilla		
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion's submitted comments)
3	DTE Electric	Kent Kujala	Abstain	
3	FirstEnergy Corp.	Richard S Hoag	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Fort Pierce Utilities Authority	Thomas Parker	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough		
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Abstain	
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach		
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Seth Shoemaker	Affirmative	
3	N.W. Electric Power Cooperative, Inc.	John Stickley	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Nebraska Public Power District comments.)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Abstain	
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie		

3	Orlando Utilities Commission	Ballard K Mutters		
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Andrea Basinski	Affirmative	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Tacoma Power	Marc Donaldson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Michael Hill)
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Barbara Kedrowski)
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen		
4	Consumers Energy Company	Tracy Goble		
4	DTE Electric	Daniel Herring	Abstain	
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Fort Pierce Utilities Authority	Javier Cisneros	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Keys Energy Services	Stan T Rzad	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Negative	SUPPORTS THIRD PARTY COMMENTS - (Michael Hill)
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Affirmative	

5	Arizona Public Service Co.	Scott Takinen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments from AZPS)
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	Basin Electric Power Cooperative	Mike Kraft	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty		
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (William English)
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources Services	Randall C Heise	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion submitted comments)
5	DTE Electric	Mark Stefaniak	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	EDP Renewables North America LLC	Heather Bowden		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Yuguang Xiao	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Abstain	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	

5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Michael Hill)
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tennessee Valley Authority	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	SUPPORTS THIRD PARTY COMMENTS - (Barbara Kedrowski)
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion's submitted comments)
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Abstain	
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Shivaz Chopra		
6	New York State Electric & Gas Corp.	Julie S King		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	

6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza		
6	Tacoma Public Utilities	Michael C Hill	Negative	COMMENT RECEIVED
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
6	Westar Energy	Tiffany Lake	Affirmative	
6	Western Area Power Administration - UGP Marketing	Mark Messerli	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway		
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake		
7	Occidental Chemical	Venona Greaff	Affirmative	
8		David L Kiguel	Affirmative	
8		Debra R Warner	Abstain	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	City of Vero Beach	Ginny Beigel	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Bob Reynolds		
10	Western Electricity Coordinating Council	Steven L. Rueckert		

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A New Jersey Nonprofit Corporation

Individual or group. (25 Responses)
Name (13 Responses)
Organization (13 Responses)
Group Name (12 Responses)
Lead Contact (12 Responses)
Question 1 (21 Responses)
Question 1 Comments (21 Responses)
Question 2 (21 Responses)
Question 2 Comments (21 Responses)
Question 3 (21 Responses)
Question 3 Comments (21 Responses)
Question 4 (21 Responses)
Question 4 Comments (21 Responses)

Group
Arizona Public Service Company
Kristie Cocco
Yes
No
The individual generating unit of a dispersed power producing resources has negligible impact on BES performance and should be completely exempt from this requirement in PRC-019,very similar to exemption in PRC-001-1.1(x). Making the standard applicable to individual disperse power producing unit is inappropriate use of the limited resources.
Yes
No
Group
Northeast Power Coordinating Council
Guy Zito
No
Although outside of the scope of the work of this Drafting Team, R3.1, as well as all Parts of this standard should be identified as 3.1, etc., and the wording in the added text made consistent with NERC format preferences. Requirement R3.1 should be Part 3.1. Because this is a format change, it should be able to be incorporated in this revision. Also outside the scope of the SAR would be a revision to the Applicability. This standard is not applicable to the Balancing Authority and Host Balancing Authority. Protective system in R3 and Part 3.1 should be replaced with the defined term Protection System. The reference to protective system in the Rationale for Applicability Exclusion in Requirement R3.1 should be revised accordingly.
Yes
Yes
We agree with the revisions proposed in footnotes 4 and 6. However, frequency and voltage protective relays require coordination with other protective relays implemented elsewhere on the BES. However, PRC-001-1.1(X) Part 3.1 is excluding coordination of protective relays for Inclusion I4 which contradicts footnotes 4 and 6.
Yes
Regarding PRC-024-1(X), the Rationale Box entitled Rationale for Footnotes 2 and 4 should be renamed Rationale for Requirement R1. Footnote 2 does not appear in R1, or on page 4 of the redline. The wording in the Rationale Box entitled Rationale for Footnotes 2 and 4 “…are set within the “no-trip zone” is confusing, as it could easily be interpreted to mean that relays should be set to

trip within the “no-trip zone” which is a contradiction. Suggest rewording to “…are set such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the “no-trip zone”...”.
Individual
John Falsey
Invenergy LLC
Individual
John Falsey
Invenergy LLC
Individual
Barbara Kedrowski
Wisconsin Electric Power Company
Yes
Yes
No
We are concerned about the evidence required for dispersed power producing resources in measures M1 and M2. Since these devices are expected to be excluded from PRC-005, we will not be required to have calibration or maintenance records for evidence of compliance. We would like measures M1 and M2 of the standard to clearly state that evidence can be original design documents and no periodic testing or verification is required.
No
Individual
David Jendras
Ameren
Individual
Maryclaire Yatsko
Seminole Electric Cooperative, Inc.
Yes
Seminole requests the drafting team to clarify that R3.1 still requires system protection coordination for generating units covered by I4 of the BES definition, however, that this coordination can take place at the aggregation or interconnection point, instead of at the individual unit.
Yes
Yes
Yes
Individual
David Kiguel
David Kiguel
No
It should be recognized that there might be cases (though rare) where coordination is actually required. Rather than removing applicability of Requirement 3.1 altogether, the standard should require that an assessment of whether coordination is required be performed jointly by the TOP and the GOP. The assessment should address any involved BES elements. If the conclusion of the assessment is that no coordination in required for certain parts of the protections, then and only then, such coordination can be omited.

Yes
Yes
No
Individual
Thomas Foltz
American Electric Power
Yes
The last sentence in the rationale box, "...do not need to be coordinated with the transmission protective systems, as this coordination would not provide reliability benefits to the BES" might be better stated as "...do not need to be coordinated directly with the transmission protective systems due to the intervening collector system(s)."
Yes
Yes
Yes
The comment form states in part "Because two of the medium-priority standards have recently been revised or are undergoing revision in another current project..." In addition, the redline version of the standard states "Given the timing of concurrent standards development of PRC projects, PRC-024-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-024." Both these comments infer that at least one other current project impacts PRC-024, but we cannot determine which project(s) that is. Could you provide some clarity on that?
Group
Dominion
Connie Low
Yes
No
Dominion does not believe the addition of 4.2.3.1 is necessary and, in fact introduces ambiguity. Some here read this addition as inferring that, only if the voltage control is applied at the individual resource (as identified in BES I4) would 4.2.3 apply to dispersed power producing resources. If SDT decides to retain, we suggest it be modified to state "This would also include voltage regulating controls that are performed solely at the individual resources dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition."
No
It is Dominions understanding that these footnotes conflict with the IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems. Given possible changes to this standard are being actively discussed, Dominion suggests these footnotes not be included until the IEEE standard has implemented a conforming change.
Yes
The language used to describe the Inclusion I4 resources is not consistent. For example: PRC-001 states "individual generating units," PRC-019 states "individual resources," and PRC-024 states "individual generating units and aggregating equipment." Dominion believes the language used in the standard revisions should be consistent with the Inclusion I4 definition. That is: a) The individual resources, and b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above
Individual
John Seelke

Public Service Enterprise Group
No
We object to part 3.1 for two reasons: First, individual dispersed resources connected to a collector system will have a protection system and breaker for each generator to isolate them for a fault on the generator-side of that breaker. In the event any individual dispersed resource Protection System or associated breaker fails, the upstream Protection System will need open the main breaker to isolate the fault. The TOP needs to be informed of the upstream protection setting associated with failure an individual generator Protection System or breaker to operate. Second, the coordination of Protections Systems between GOs and TOs is the subject of Project 2007-06 – System Protection Coordination, and Project 2014-01's SDT should send their concerns to this team so they may address them in their project.
Yes
Yes
No
Group
MRO NERC Standards Review Forum
Joe DePoorter
Yes
Yes
No
In order to provide relief for individual DGRs not being within compliance, the NSRF does recommend that perhaps there could be another set of VSLs established exclusively for DGRs. Case in point, if the entity finds one DGR that is not within the prescribed measures of Attachment 1 or 2, the entity would not be found non-compliant. Our recommendation would be for the Low VSL to >5% of DRGs were not within prescribed settings per Attachment 1 and 2 per of the aggregated Facility. This would allow a very small number of DGRs to have an issue. Or words to that affect. The NSRF believes this recommendation is aligned with the RAI program since one DGR (not within prescribed limits) will not impact the reliability of the BES.
No
Group
Corporate Compliance
Dianne Gordon
Yes
Yes
A possible edit would be to change 4.2.3.1 (regarding individual dispersed gen units) to 4.2.4. This may make the meaning of types of "Applicable Facilities" more clear to the reader.
Yes
Footnotes might be more clear if the language "....(potentially including non-BES equipment)..." were added.
No
Individual
Michael Hill
Tacoma Public Utilties

Yes
Yes
No
The changes to PRC-024-1(X) include the applicability of the standard to Bulk Power System equipment that is not BES equipment. The purpose of the BES definition is to provide bright line applicability criteria for utilities to better understand which assets are subject to regulatory standards. The revision contained in PRC-024-1(X) deviate from the BES definition. If NERC would like to include Non-BES equipment in the regulatory standards then NERC should modify the BES definition to that end. Should Rationale for Footnotes 2 and 4 be changed to Rationale for Footnotes 4 and 6?
No
Group
PacifiCorp
Sandra Shaffer
Yes
Yes
Yes
No
Group
SERC PCS
David Greene
Yes
Yes
If it is the intention of the SDT to exclude individual dispersed power producing resources from the list of Applicable Facilities when voltage regulating control is not performed solely at the individual resources, we suggest that the SDT include the word “only” in R4.2.3.1. “This includes individual dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition only where voltage regulating control for the facility is performed solely at the individual resources”
Yes
No
The comments expressed herein represent a consensus of the views of the above-named members of the SERC PCS only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Individual
Michelle R. DAntuono
Ingleside Cogeneration LP
No
Ingleside Cogeneration LP (ICLP) believes that the project team’s intent in R3.1 is to ensure that only the Protection Systems corresponding to 75+ MVA points of aggregation are applicable, but is not comfortable that the proposed update captures that point. In fact, it seems to only exclude those components protecting individual solar panels/windmills from the requirement to coordinate new

deployments and modifications with the BA and TOP. In our view, the intermediate aggregation points less than 75 MVA are of no practical interest to the BA and TOP – and should be specifically excluded from the requirement. Similarly, the applicability of Requirements R1, R2.1, and R5.1 should be limited to 75+ MVA aggregation points. Protection System awareness, failures that "reduce system reliability", and changes in operating conditions that may affect a TOP's Protection System are only meaningful at those capacity levels. In fact, if too much attention is placed on large numbers of very low-impact systems, there will less consideration made for those that really do present a risk to the BES.
No
ICLP believes that the way that the applicability criteria in PRC-019-2 has been re-framed only includes voltage regulating controls at the single dispersed unit level and at aggregation points at 75 MVA or greater. This omits those voltage controllers serving an entire string of wind mills or solar panels with combined capacity less than 75 MVA. We do not think that was the drafting team's intent, and suggest that the language be clarified.
Yes
ICLP agrees that it makes sense to set the voltage and frequency ride-through settings consistently throughout a dispersed generation facility. We can think of no good technical reason to do otherwise. ICLP is concerned that an overly-enthusiastic CEA could assess a violation if a single relay record is missing among the thousands that would be covered by PRC-024-1(X), but agree that the RAI initiative has established an environment where a more reasonable compliance approach will be the norm.
No
Group
ACES Standards Collaborators
Jason Marshall
No
While we agree with the concepts and intent to exclude applicability of sub-requirement R3.1 to the individual units of dispersed power producing resources, we do not believe the actual implementation is correct. In an August 10, 2009 informational filing, NERC indicated to the Commission that they would use bulleted lists to indicate when "components may reflect a list of options that may be undertaken to achieve compliance." Thus, we do not see how a sub-bullet of a sub-requirement can be used to change the applicability of the requirement. We believe the applicability section should be modified to limit applicability of the requirement.
No
We do not oppose applicability of PRC-019 to the individual dispersed power producing resources where voltage regulating control is performed at the individual unit. However, the proposed changes do not accomplish this and actually only serve to confuse the applicability of the standard. All NERC standards are applicable to individual Elements of the BES definition. Since the BES definition includes the individual units of dispersed power producing resource, PRC-019-2 is applicable to those units. Adding sub-section 4.2.3.1 that states this includes "individual dispersed power producing resources… where voltage regulating control for the facility is performed solely at the individual resources" does not add these Elements as they were already included. Furthermore, it does not exclude those individual dispersed power producing resources where voltage regulating control is performed at the aggregate level. The bottom line is that the rationale that is explained in the standard is not accomplished by this change. We believe this standard does not require modification to include "individual dispersed power producing resources… where voltage regulating control for the facility is performed solely at the individual resources" as these resources are already included. However, an explanation in the application guidelines section of the standard is warranted to explain the applicability.
Yes
No
Thank you for the opportunity to comment.

Individual
Larry Heckert
Alliant Energy
Yes
Yes
No
PRC-024-1X requirements R1 and R2 are using the terms “Protective Relaying” and “Protective Relay” with no definition provided for these terms within the NERC glossary of terms or within the standard itself. Footnote 3 is used to define how the term should be applied. The footnote suggests the previously undefined term “Protective Relaying” would be inclusive of any control equipment that contains protective functions. Although the footnote is only represented in standard PRC-024-01(X) and theoretically does not apply to other standards, it could introduce confusion in the other NERC standards that use these terms (e.g., if excitation controls are considered protective relaying under PRC-024, would they be considered as part of a protection system and require utilities to keep excitation control maintenance records under PRC-005?).
No
Group
SPP Standards Review Group
Shannon V. Mickens
Yes
Yes
Yes
Yes
We would suggest to the drafting team in reference to PRC-001-1.1(X) that you would evaluate adding the remaining Measures (M4, M5 and M6) to that particular section. Our concern would be that all the Measures Data pertaining to the Requirements has not been included and this has the potential of causing confusion on what evidence should be provided in an audit. Additionally, we would like the drafting team to provide more clarity on the why there’s a Rationale Box for Footnotes 2 and 4 in reference to PRC-024-1(X). Footnote 2 pertains to interchangeable terms which has been revised to align with the definition of the BES. If the drafting team’s objective is to focus on Footnotes 4 and 6, we would suggest changing the header of the Rationale Box to read “Rationale for Footnotes 4 and 6”. Finally, we would suggest to the drafting team adding Rationale Boxes to all three standards. We feel this would provide clarity to the industry on the expectations of the Requirements in the standards as well as promoting consistency with other documentation associated with this project.
Individual
Venona Greaff
Occidental Chemical Corporation
Group
Bonneville Power Administration
Andrea Jessup
Yes
Yes

Yes
No
Individual
Jamison Cawley
Nebraska Public Power District
Yes
Yes
No
In the Rationale for Footnotes 2 and 4, the phrase “including any non-Bulk Electric System collection system equipment” is used. We feel this statement and approach need to be removed because this standard revision hinges on Inclusion I4 of the BES Definition. It is overreaching to add non-BES equipment into a standard. The BES definition serves to identify what facilities are or are not applicable to NERC standards. We feel this adds back to the confusion that was to be avoided with the revised BES Definition.
No
Group
FirstEnergy
Doug Hohlbaugh
Yes
While FirstEnergy (FE) agrees with the exclusion, it should not simply be left to inference that the remainder of the standard does apply to the I4 units at the collector or interconnection point. See FE comments to Question 4 for our suggested approach to add clarity.
Yes
See FE comments to Question 4.
Yes
FE agrees that the PRC-024-1 standard in regard to NERC BES facilities I4 should apply to the voltage protective relays applied on the individual power producing resources, as well as voltage protective relays applied on equipment from the individual power producing resource up to the point of interconnection. However, we believe the SDT should make use of a Facilities Applicability section 4.2 as is done in many NERC standards such as PRC-019-2. By adding a section 4.2, it would avoid the need for the footnote approach and make it clearer that the standard is applicable to the dispersed generation equipment by simply evaluating the Applicability Section and having two subsections 4.1 Functional Entities and 4.2 Facilities. See FE comments to Question 4 for additional information.
Yes
FE suggests the standard drafting team give consideration for making consistent use of Section 4 to include both a sub-section 4.1 Functional Entities and 4.2 Facilities. This would alleviate the need to bury pertinent information and clarity around what facilities are in scope within footnotes. Currently only PRC-019 includes both of these applicability sub-sections and they should be used in each standard. The sections may need to be written differently in each of the three standards but should be used in each. Furthermore, standard PRC-019-2 which currently uses sub-section 4.2 Facilities includes text that is simply repeats of what is stated in NERC BES Inclusion statement I2 which could be revised/simplified. As an example, FE believes that section 4 of PRC-019-2 could be written as follows: 4 Applicability 4.1 Functional Entities 4.1.1 Generator Owner 4.1.2 Transmission Owner 4.2 Facilities 4.2.1 Generator Owner – for the purpose of this standard, the term, “applicable Facility” shall mean NERC BES Definition Inclusion I2 and I4. Where voltage regulating control for the BES generation facility is performed solely at the individual resources, those facilities are also included. 4.2.2 Transmission Owner - for the purpose of this standard, the term, “applicable Facility”

shall mean a synchronous condenser that is a qualifying BES facility under NERC BES Definition Inclusion I5. As another example, standard PRC-001-1.1 could be written as follows: 4 Applicability 4.1 Functional Entities 4.1.1 Balancing Authorities 4.1.2 Transmission Operators 4.1.3 Generator Operators 4.2 Facilities 4.2.1 – This standard applies to all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher as clarified by the NERC BES definition Inclusion statements. In regard to Inclusion I4 this standard is not applicable to the individual generating units of dispersed power producing resources. One additional suggestion: Lastly, throughout the various standards there is a footnote indicating "The terms 'dispersed generation resources' and 'dispersed power producing resources' are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES." It appears this footnote is for informational purposes only during the development of standard and will be removed in the final clean version. If that is not the case, consider the need for a NERC Glossary of Term for Dispersed Generation Resource that would indicate it is synonymous with the NERC BES Definition in regard to Inclusion statement I4 for dispersed power producing resources.
Group
DTE Electric
Kathleen Black
Yes
No
This standard applies at the individual wind turbine level which is inconsistent with the revisions to PRC-001, PRC-004 and VAR-002,where the standards only apply where there is 75 MVA connected at 100kV or higher.
No
Please see our comment for Question 2.
No
No comment.

Additional Comments:

MS Energy
Lance Bean

PRC-001-1.1(X)

- In the new bullet item of R3.1, the standards drafting team refers to individual "generating units". The BES definition Inclusion I4 includes the individual "resources". In PRC-001-1.1(X), would it make sense to replace "generating units" with "resources" to be consistent with the BES definition?

PRC-024-1(X)

- Ahead of the Introduction, there is a statement "the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard". The text box is not in the Applicability section, it is in B. Requirements, R1.
- The text box title is "Rationale for Footnotes 2 and 4". The two new footnotes are 4 and 6. I assume footnotes 1 & 2 will be removed once the Standard is approved, so perhaps the existing title is acceptable.

- The text box refers to individual “generating units”. I think “generating units” should be changed to “resources”.
- The text box also includes the text “it is appropriate to require that protective relay settings…are set within the no-trip zone”. I think the statement should be “it is appropriate to require that protective relay settings…are **not** set within the no-trip zone”

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project 2014-01 Standards Applicability for Dispersed Generation Resources

The Project 2014-01 Drafting Team thanks all commenters who submitted comments on the standard. These standards were posted for a 45-day public comment period from November 5, 2014 through December 23, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 25 sets of comments, including comments from approximately 98 different people from approximately 69 companies representing all 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

This document contains the Project 2014-01 Standards Applicability for Dispersed Generation Resources (DGR) standard drafting team's (SDT) response to all industry comments received during this comment period. The DGR SDT encourages commenters to review its responses to ensure all concerns have been addressed. The DGR SDT notes that a significant majority of commenters agree with the DGR SDT's recommendations on the standards, but that several commenters expressed specific concerns. Some comments supporting the DGR SDT's recommendations are discussed below but in most cases are not specifically addressed in this response. Also, several comments in response to specific questions are duplicated in other questions, and several commenters raise substantively the same concerns as others. Therefore, the DGR SDT's consideration of all comments is addressed in this section in summary form, with duplicate comments treated as a single issue. Any comments made on another standard are addressed in the DGR SDT's response to comments on that standard.

1. Summary Consideration

Based on the results from the recent comment and ballot period, it appears that industry overwhelmingly agrees with the DGR SDT's recommendations on applicability changes to PRC-001; PRC-019; and PRC-024, to account for the unique characteristics of dispersed power producing resources[1] in the standards. However, there are some disagreements among stakeholders and suggestions for language revisions contained in industry comments. To the extent that there are comments beyond the scope of this SDT, those comments will be communicated to the appropriate team for consideration.

[1] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

The DGR SDT has carefully reviewed and considered each stakeholder comment and has revised its recommendations where suggested changes improve clarity and are consistent with DGR SDT intent and apparent industry consensus. Several commenters suggested non-substantive language changes for standard language as well as explanatory language, such as language in particular rationale boxes. The DGR SDT has carefully considered each comment and has implemented revisions as follows:

- The DGR SDT made non-substantive revisions to the align the terms referring to individual generating units of the dispersed power producing resources in PRC-001; PRC-019; and PRC-024 with one another.

- The DGR SDT revised the language in the Description of Current Draft section of PRC-001; PRC-019; and PRC-024 and PRC-001 the standard, as well as similar language in the standard's Implementation Plan to reflect that there are not any other current projects seeking to revise those standards.

All recommended changes are non-substantive as contemplated by the NERC Standard Processes Manual and therefore do not require an additional ballot. The DGR SDT's consideration of all comments follows.

2. General Comments

At least one commenter recommended that the language describing individual generating units in PRC-001; PRC-019; and PRC-024 should be aligned with one another. The DGR SDT agrees and has therefore made non-substantive revisions to the terms to provide consistency of language among the recommended modifications.

At least one commenter requested that the DGR SDT consider the need for a NERC Glossary term for dispersed generation resource that would indicate it is synonymous with the NERC BES Definition in regard to Inclusion statement I4 for dispersed power producing resources to address the information contained in the footnote in the standard that indicates "the terms 'dispersed generation resources' and 'dispersed power producing resources' are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES." The DGR SDT expects the use of the terms will be transitional, and that the term used in the NERC BES definition, as included in the Glossary of Terms Used in NERC Reliability Standards, will be the only term used to refer to dispersed generation resources on a going forward basis.

At least one commenter noted that the comment form states in part "because two of the medium-priority standards have recently been revised or are undergoing revision in another current project...," and that additionally, the redline version of the standard states "given the timing of concurrent standards development of PRC projects, PRC-024-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-024," but that they were unable to determine another project seeking to revise the standard. The DGR SDT agrees that there are not any other current projects seeking to revise

PRC-024, and has revised the language in the Description of Current Draft section of the standard, as well as similar language in the standard's Implementation Plan.

3. PRC-001

At least one commenter suggested that the applicability sections should be modified to limit applicability of the requirements, rather than using "sub-bullets." The SDT maintains that the approach of utilizing "sub-bullets" to change applicability has been supported by NERC staff during modification of this and other standards, and it is the position of the SDT that the current modification allows specific requirements to be targeted as needed, and that this approach appears to be overwhelmingly supported by the majority of the industry as evidenced by the submitted responses. Therefore, the DGR SDT declines to adopt this suggestion.

One commenter suggested that the standards should require an assessment of whether coordination must be performed jointly by the TOP and the GOP as an alternative to the DGR SDT's suggested changes. Additional coordination is not precluded by the revised standard. Adding a further requirement to jointly assess the necessity of coordination between the TOP, host BA, and the GOP is beyond the scope of the DGR SDT. It is the DGR SDT's position that the proposed revisions to the standard adequately support reliability and are consistent with current practices. Therefore, the SDT declines to adopt this suggestion.

At least one commenter expressed concern that there may be situations where the TOP should be informed of the upstream protection settings associated with failure of an individual generator Protection System or breaker to operate, and also suggested that the coordination of Protections Systems between GOs and TOs is the subject of Project 2007-06 - System Protection Coordination, and requested that the DGR SDT communicate their comments to that team so they may address them in their project as they determine appropriate. While the DGR SDT's position will be communicated to the Project 2007-06 SDT, there is a need to address PRC-001 directly as this is still the effective standard. In the proposed modification, the "upstream protection systems," that are at the point of aggregation of 75 MVA or greater are still in scope for dispersed power producing resources, and as such, will be coordinated with the TOP and host BA.

At least one commenter requested the drafting team clarify that R3.1 still requires system protection coordination for generating units covered by I4 of the BES definition, but that the coordination can take place at the aggregation or interconnection point, rather than at the individual unit level. Also, another commenter expressed concern that R3.1 only excludes individual generator protection equipment from coordinating with the host BA and TOP, and stated that, similarly, the applicability of Requirements R1, R2.1, and R5.1 should be limited to aggregation points greater than 75 MVA. The DGR SDT maintains that the proposed requirements of the standard adequately support reliability and are consistent with current practices. The proposed modifications to the standard limit the requirements to protective systems associated with the facilities at the point of aggregation of 75 MVA or greater (i.e. substation level protection systems). The applicability for Requirements R1 and R2.1 are explained in the White

Paper. The DGR SDT has determined that the language; “that could require changes in the protection systems of others” adequately limits the scope of requirement R5.1.

One commenter requested that the DGR SDT consider adding Measures to Requirements R4, R5, and R6 of PRC-001; however, addressing Measures for which the DGR SDT did not modify the associated Requirement is beyond the scope of the DGR SDT’s SAR.

4. PRC-019

At least one commenter suggested that individual generating units of dispersed power producing resources should be completely exempt from PRC-019’s requirements, noting the similarity to the exemption in PRC-001-1.1(ii). Similarly, a commenter stated that applying the standard to the individual wind turbine level is inconsistent with the revisions to PRC-001, PRC-004 and VAR-002. It is the position of the DGR SDT that it is necessary to coordinate voltage regulating controls with the TOP and in the case where voltage control is solely accomplished at the individual unit level, the individual units should be included in the scope of this standard. The DGR SDT has maintained a consistent approach to its recommendations. The DGR SDT maintains that the standard should be applied at the individual unit level, as stated in 4.2.3.1., in order to accomplish the objective of the standard.

At least one commenter expressed concern that the applicability of PRC-019-2 excludes voltage regulating controllers serving a multiplicity of individual generating units with a combined capacity less than 75 MVA. The DGR SDT understands the comment to refer to voltage regulating control at the generating plant/Facility level of BES generators identified through inclusion I4 of the BES definition; however, the revisions to the standard proposed by the DGR SDT expanded the applicability from voltage regulating control at the plant/Facility level, such as voltage controllers serving a multiplicity of individual generating units, to also include individual generating units.

5. PRC-024

At least one commenter suggested that the footnotes conflict with the IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems and suggested the footnotes should not be included until the IEEE standard has implemented a conforming change. It is the position of the SDT that addressing IEEE 1547 is beyond the scope of the SDT, as it is not referenced in PRC-024.

At least one commenter suggested the DGR SDT consider including the following sub-sections: 4.1 Functional Entities and 4.2 Facilities rather than using footnotes; however, using a footnote to revise applicability has been supported by NERC staff during modification of this standard. The SDT therefor believes the proposed modification is satisfactory and thus declines to incorporate the suggested modification.

At least one commenter recommended establishing another set of VSLs established exclusively for DGRs. The DGR SDT agrees that the magnitude of the reliability impact of an individual DGR unit with non-compliant settings should be addressed; however, it is the position of the DGR SDT that this issue is better addressed during the compliance enforcement process. Further, risk assessments performed during RAI should address this issue. The DGR SDT believes the nature of the requirements of Requirements R1 and R2 lend themselves for a pass/fail VSL; therefore, designing a range of severity of non-compliance is inappropriate based on VSL guidelines.

At least one commenter requested that Measures M1 and M2 of the standard clearly state that evidence can be original design documents and no periodic testing or verification is required. The SDT does not see a need to specify what evidence is acceptable strictly for dispersed power producing resources. The SDT believes that the existing use of "evidence" is broad enough to capture the commenter's intent.

At least one commenter stated that the changes to PRC-024-1(X) include the applicability of the standard to Bulk Power System equipment that is not BES equipment, and indicated that the BES definition should be modified to include non-BES equipment in the regulatory standards rather than particular standards. Similarly, one commenter suggested that the language "including any non-Bulk Electric System collection system equipment" should be omitted from the rationale for footnotes 2 and 4, because the BES definition serves to identify what facilities are or are not applicable to NERC standards.
Reliability standards may apply to specific equipment characteristics, which may include equipment not included through the BES definition. It is not in the DGR SDT's scope of work to modify the definition of BES.

At least one commenter suggested that the language in the Rationale Box entitled Rationale for Footnotes 2 and 4 "...are set within the "no-trip zone" is confusing and should be revised. The DGR SDT provided clarifying language.

At least one commenter expressed concern that the use of the terms "Protective Relaying" and "Protective Relay" in Requirements R1 and R2 may introduce confusion in other standards that use the same or similar terms, since, although footnote 3 provides further information about the term, a definition of the terms is not provided in the standard or in the Glossary of Terms Used in NERC Reliability Standards. The terms "protective relaying" and "protective relay" are not capitalized, and are not defined terms as used in Requirements R1 and R2, nor are the terms capitalized or used as defined terms in footnote 3; therefore the use of the terms in this standard have no bearing on the use of the same or similar terms in other standards. The requirement language and footnote 3 address aspects of the standard that were in the previously approved version and not associated with the applicability of dispersed power producing resources, as such revisions to these items are not in the scope of the SDT DGR's SAR to change.

At least one commenter expressed agreement with the revisions proposed in footnotes 4 and 6, but noted that frequency and voltage protective relays require coordination with other protective relays implemented elsewhere on the BES, and expressed concern that PRC-001-1.1(ii) Part 3.1 is excluding coordination of protective relays for Inclusion I4 which contradicts footnotes 4 and 6. While PRC-001-1.1(ii) excludes coordination of new or changes to existing relays with the TOP and host BA, PRC-024 still requires that these relays be set respecting the "no-trip zone." The SDT does not believe there is a contradiction as the PRC standards address different compliance aspects associated with these relays. Further, PRC-024 Requirement R4 requires the reporting of such relay settings to the TP and PC.

At least one commenter suggested revising the language of the footnotes to add ". . . (potentially including non-BES equipment)..." Thank you for your comment. It is the SDT's position that the language of the footnote as drafted is sufficiently clear and unambiguous.

At least one commenter agreed that the PRC-024-1 standard in regard to NERC BES facilities I4 should apply to the voltage protective relays applied on the individual power producing resources, as well as voltage protective relays applied on equipment from the individual power producing resource up to the point of interconnection. However, the commenter expressed that the SDT should make use of a Facilities Applicability section 4.2 as is done in many NERC standards such as PRC-019-2 rather than using a footnote. The approach of utilizing the footnote to revise applicability has been supported by NERC staff members during modification of this standard. The SDT believes the proposed modification is satisfactory and thus declines to incorporate the suggested modification.

At least one commenter agreed that it is sensible to set the voltage and frequency ride-through settings consistently throughout a dispersed generation facility: however, the commenter expressed concern that a violation may be assessed if a single relay record is missing among the potentially thousands of relays that would be covered by PRC-024-2. The commenter went on to note that they agree that the RAI initiative has established an environment where a more reasonable compliance approach will be the norm. How violations are processed by NERC compliance is not in the purview of the DGR SDT.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[2]

[2] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

1. **Do you agree with the revisions proposed in PRC-001-1.1(X) Requirement R3 part 3.1 to exclude the individual generating units of dispersed power producing resources identified through Inclusion I4 of the BES definition from this requirement? If not, please provide technical rationale for your disagreement, along with suggested language changes.** 14
2. **Do you agree with the revisions proposed in the Facilities section of proposed PRC-019-2 to clarify that the standard is applicable to dispersed power producing resources identified through Inclusion I4 of the BES definition where voltage regulating contol for the facility is performed solely at the individual resource? If not, please provide technical rationale for your disagreement, along with suggested language changes.** 18
3. **Do you agree with the revisions proposed in PRC-024-1(X) to clarify (via footnotes 4 and 6) that Requirements R1 and R2 are applicable to both dispersed power producing resources identified through Inclusion I4 of the BES definition, as well as any aggreating equipment (potentially including non-BES equipment) from the individual resource up to the point of interconnection? If not, please provide technical rationale for your disagreement, along with suggested language changes.** 22
4. **Do you have any additional comments to assist the DGR SDT in further developing its recommendations?** 26

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Kristie Cocco	Arizona Public Service Company			X		X	X				
N/A													
2.	Group	Guy Zito	Northeast Power Coordinating Council										X

.

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Kathleen Goodman	ISO - New England	NPCC	2

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

8.	Michael Jones	National Grid	NPCC	1
9.	Mark Kenny	Northeast Utilities	NPCC	1
10.	Helen Lainis	Independent Electricity Suystem Operator	NPCC	2
11.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
12.	Bruce Metruck	New York Power Authority	NPCC	6
13.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
14.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
21.	Brian Shanahan	National Grid	NPCC	1
22.	Wayne Sipperly	New York Power Authority	NPCC	5
23.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5

3.	Group	Connie Low	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Randi Heise	NERC Compliance Policy	NPCC	5
2.	Louis Slade	NERC Compliance Policy	SERC	1, 3, 5, 6
3.	Larry Nash	Electric Transmission	SERC	
4.	Chip Humphrey	Power Generation Compliance	NPCC	5
5.	Louis Slade	NERC Compliance Policy	RFC	5, 6

4.	Group	Joe DePoorter	MRO NERC Standards Review Forum	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Amy Casucelli	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power Company	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative, Inc.	MRO	1, 2, 5, 6
4.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jenson	Western Area Power Administration	MRO	1, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

7.	Joseph DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
10.	Marie Knox	Midwest ISO Inc.	MRO	2
11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12.	Randi Nyholm	Minnesota Power	MRO	1, 5
13.	Scott Nickels	Rochester Public Utilities	MRO	4
14.	Terry Harbour	MidAmerican Energy COmpany	MRO	1, 3, 5, 6
15.	Tom Breene	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6
16.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

5.	Group	Dianne Gordon	Corporate Compliance	X		X		X						
N/A														
6.	Group	Sandra Shaffer	PacifiCorp						X					
N/A														
7.	Group	David Greene	SERC PCS											X

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Miller	GTC	SERC	1
2.	Paul Nauert	Ameren	SERC	1, 3
3.	Greg Davis	GTC	SERC	1
4.	James Evans	SCE&G	SERC	1, 3, 5, 6
5.	Steve Edwards	Dominion	SERC	1, 3, 6
6.	George Pitts	TVA	SERC	1, 3, 5, 6

8.	Group	Jason Marshall	ACES Standards Collaborators						X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bob Solomon	Hoosier Energy	RFC	1
2.	Paul Jackson	Buckeye Power	RFC	3, 4, 5
3.	Scott Brame	North Carolina Electric Membership Corporation	SERC	3, 4, 5
4.	Ginger Mercier	Prairie Power	SERC	3
5.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
6.	Chip Koloini	Golden Spread Electric Cooperative	ERCOT	3, 5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
9.	Group	Shannon V. Mickens	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	john falsey	Invenergy LLC	NA - Not Applicable	NA
2.	Stephanie Johnson	Westar Energy, Inc.	SPP	1, 3, 5, 6
3.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
4.	Luis Zaragoza	Sunflower Electric Power Corporation	SPP	1
5.	James Nail	City of Independence, Missouri	SPP	3, 5
6.	Jonathan Hayes	Southwest Power Pool	SPP	2
7.	Robert Rhodes	Southwest Power Pool	SPP	2
8.	Shannon Mickens	Southwest Power Pool	SPP	2

10.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Steve Enyeart	Customer Service Engineering	WECC	1

11.	Group	Doug Hohlbaugh	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Smith	FE - RBB - Seg 1	RFC	1
2.	Rich Hoag	FE - RBB - Seg 3	RFC	3
3.	Doug Hohlbaugh	FE - RBB - Seg 4	RFC	4
4.	Ken Dresner	FE - RBB - Seg 5	RFC	5
5.	Kevin Querry	FE - RBB - Seg 6	RFC	6
6.	Phil Bowers	FE - TO SME	RFC	1
7.	Bill Duge	FE - GO SME	RFC	5
8.	Rusty Loy	FE - GO SME	RFC	5
9.	Steve Wittenauer	FE - TO SME	RFC	1

12.	Group	Kathleen Black	DTE Electric			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kent Kujala	NERC Compliance	RFC	3
2.	Daniel Herring	NERC Training & Standards Development	RFC	4
3.	Mark Stefaniak	Merchant Operations	RFC	5
4.	Neil Kennings	Renewable Energy		

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
5. Barbara Scramlin		DO SOC											
13.	Individual	John Falsey	Invenergy LLC					X					
14.	Individual	John Falsey	Invenergy LLC					X					
15.	Individual	Barbara Kedrowski	Wisconsin Electric Power Company			X	X	X					
16.	Individual	David Jendras	Ameren	X		X		X	X				
17.	Individual	Maryclaire Yatsko	Seminole Electric Cooperative, Inc.	X		X	X	X	X				
18.	Individual	David Kiguel	David Kiguel								X		
19.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
20.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
21.	Individual	Michael Hill	Tacoma Public Utilties	X		X	X	X	X				
22.	Individual	Michelle R. DAntuono	Ingleside Cogeneration LP					X					
23.	Individual	Larry Heckert	Alliant Energy				X						
24.	Individual	Venona Greaff	Occidental Chemical Corporation							X			
25.	Individual	Jamison Cawley	Nebraska Public Power District	X		X		X					

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Organization	Agree	Supporting Comments of "Entity Name"
Invenergy LLC	Agree	Southwest Power Pool
Ameren	Agree	We agree with and adopt the SERC PCS comments for Project 2014-01.
Occidental Chemical Corporation	Agree	Ingleside Cogeneration, LP

1. **Do you agree with the revisions proposed in PRC-001-1.1(X) Requirement R3 part 3.1 to exclude the individual generating units of dispersed power producing resources identified through Inclusion I4 of the BES definition from this requirement? If not, please provide technical rationale for your disagreement, along with suggested language changes.**

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	Although outside of the scope of the work of this Drafting Team, R3.1, as well as all Parts of this standard should be identified as 3.1, etc., and the wording in the added text made consistent with NERC format preferences. Requirement R3.1 should be Part 3.1. Because this is a format change, it should be able to be incorporated in this revision. Also outside the scope of the SAR would be a revision to the Applicability. This standard is not applicable to the Balancing Authority and Host Balancing Authority. Protective system in R3 and Part 3.1 should be replaced with the defined term Protection System. The reference to protective system in the Rationale for Applicability Exclusion in Requirement R3.1 should be revised accordingly.
ACES Standards Collaborators	No	While we agree with the concepts and intent to exclude applicability of sub-requirement R3.1 to the individual units of dispersed power producing resources, we do not believe the actual implementation is correct. In an August 10, 2009 informational filing, NERC indicated to the Commission that they would use bulleted lists to indicate when "components may reflect a list of options that may be undertaken to achieve compliance." Thus, we do not see how a sub-bullet of a sub-requirement can be used to change the applicability of the requirement. We believe the applicability section should be modified to limit applicability of the requirement.
David Kiguel	No	It should be recognized that there might be cases (though rare) where coordination is actually required. Rather than removing applicability of Requirement 3.1 altogether, the standard should require that an assessment of whether coordination is required be performed jointly by the

Organization	Yes or No	Question 1 Comment
		TOP and the GOP. The assessment should address any involved BES elements. If the conclusion of the assessment is that no coordination in required for certain parts of the protections, then and only then, such coordination can be omited.
Public Service Enterprise Group	No	We object to part 3.1 for two reasons: First, individual dispersed resources connected to a collector system will have a protection system and breaker for each generator to isolate them for a fault on the generator-side of that breaker. In the event any individual dispersed resource Protection System or associated breaker fails, the upstream Protection System will need open the main breaker to isolate the fault. The TOP needs to be informed of the upstream protection setting associated with failure an individual generator Protection System or breaker to operate. Second, the coordination of Protections Systems between GOs and TOs is the subject of Project 2007-06 - System Protection Coordination, and Project 2014-01's SDT should send their concerns to this team so they may address them in their project.
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP (ICLP) believes that the project team's intent in R3.1 is to ensure that only the Protection Systems corresponding to 75+ MVA points of aggregation are applicable, but is not comfortable that the proposed update captures that point. In fact, it seems to only exclude those components protecting individual solar panels/windmills from the requirement to coordinate new deployments and modifications with the BA and TOP. In our view, the intermediate aggregation points less than 75 MVA are of no practical interest to the BA and TOP - and should be specifically excluded from the requirement. Similarly, the applicability of Requirements R1, R2.1, and R5.1 should be limited to 75+ MVA aggregation points. Protection System awareness, failures that "reduce system reliability", and changes in operating conditions that may affect a TOP's Protection System are only meaningful at those capacity levels. In fact, if too much attention is placed on large numbers of very low-impact systems,

Organization	Yes or No	Question 1 Comment
		there will less consideration made for those that really do present a risk to the BES.
Arizona Public Service Company	Yes	
Dominion	Yes	
MRO NERC Standards Review Forum	Yes	
Corporate Compliance	Yes	
PacifiCorp	Yes	
SERC PCS	Yes	
SPP Standards Review Group	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	Yes	While FirstEnergy (FE) agrees with the exclusion, it should not simply be left to inference that the remainder of the standard does apply to the I4 units at the collector or interconnection point. See FE comments to Question 4 for our suggested approach to add clarity.
DTE Electric	Yes	
Wisconsin Electric Power Company	Yes	
Seminole Electric Cooperative, Inc.	Yes	Seminole requests the drafting team to clarify that R3.1 still requires system protection coordination for generating units covered by I4 of the BES

Organization	Yes or No	Question 1 Comment
		definition, however, that this coordination can take place at the aggregation or interconnection point, instead of at the individual unit.
American Electric Power	Yes	The last sentence in the rationale box, "...do not need to be coordinated with the transmission protective systems, as this coordination would not provide reliability benefits to the BES" might be better stated as "...do not need to be coordinated directly with the transmission protective systems due to the intervening collector system(s)."
Tacoma Public Utilties	Yes	
Alliant Energy	Yes	
Nebraska Public Power District	Yes	
Invenergy LLC		

2. Do you agree with the revisions proposed in the Facilities section of proposed PRC-019-2 to clarify that the standard is applicable to dispersed power producing resources identified through Inclusion I4 of the BES definition where voltage regulating control for the facility is performed solely at the individual resource? If not, please provide technical rationale for your disagreement, along with suggested language changes.

Organization	Yes or No	Question 2 Comment
Arizona Public Service Company	No	The individual generating unit of a dispersed power producing resources has negligible impact on BES performance and should be completely exempt from this requirement in PRC-019, very similar to exemption in PRC-001-1.1(x). Making the standard applicable to individual disperse power producing unit is inappropriate use of the limited resources.
Dominion	No	Dominion does not believe the addition of 4.2.3.1 is necessary and, in fact introduces ambiguity. Some here read this addition as inferring that, only if the voltage control is applied at the individual resource (as identified in BES I4) would 4.2.3 apply to dispersed power producing resources. If SDT decides to retain, we suggest it be modified to state "This would also include voltage regulating controls that are performed solely at the individual resources dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition."
ACES Standards Collaborators	No	We do not oppose applicability of PRC-019 to the individual dispersed power producing resources where voltage regulating control is performed at the individual unit. However, the proposed changes do not accomplish this and actually only serve to confuse the applicability of the standard. All NERC standards are applicable to individual Elements of the BES definition. Since the BES definition includes the individual units of dispersed power producing resource, PRC-019-2 is applicable to those units. Adding sub-section 4.2.3.1 that states this includes "individual dispersed power producing resources... where voltage regulating control for the facility is performed solely at the individual resources" does not add these Elements as they were already included. Furthermore, it does not exclude those individual dispersed power producing resources where voltage regulating control is performed at the aggregate level. The bottom line is that the rationale that is explained in the

Organization	Yes or No	Question 2 Comment
		standard is not accomplished by this change. We believe this standard does not require modification to include "individual dispersed power producing resources... where voltage regulating control for the facility is performed solely at the individual resources" as these resources are already included. However, an explanation in the application guidelines section of the standard is warranted to explain the applicability.
DTE Electric	No	This standard applies at the individual wind turbine level which is inconsistent with the revisions to PRC-001, PRC-004 and VAR-002, where the standards only apply where there is 75 MVA connected at 100kV or higher.
Ingleside Cogeneration LP	No	ICLP believes that the way that the applicability criteria in PRC-019-2 has been re-framed only includes voltage regulating controls at the single dispersed unit level and at aggregation points at 75 MVA or greater. This omits those voltage controllers serving an entire string of wind mills or solar panels with combined capacity less than 75 MVA. We do not think that was the drafting team's intent, and suggest that the language be clarified.
Northeast Power Coordinating Council	Yes	
MRO NERC Standards Review Forum	Yes	
Corporate Compliance	Yes	A possible edit would be to change 4.2.3.1 (regarding individual dispersed gen units) to 4.2.4. This may make the meaning of types of "Applicable Facilities" more clear to the reader.
PacifiCorp	Yes	

Organization	Yes or No	Question 2 Comment
SERC PCS	Yes	If it is the intention of the SDT to exclude individual dispersed power producing resources from the list of Applicable Facilities when voltage regulating control is not performed solely at the individual resources, we suggest that the SDT include the word “only” in R4.2.3.1. “This includes individual dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition only where voltage regulating control for the facility is performed solely at the individual resources”
SPP Standards Review Group	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	Yes	See FE comments to Question 4.
Wisconsin Electric Power Company	Yes	
Seminole Electric Cooperative, Inc.	Yes	
David Kiguel	Yes	
American Electric Power	Yes	
Public Service Enterprise Group	Yes	
Tacoma Public Utilties	Yes	
Alliant Energy	Yes	

Organization	Yes or No	Question 2 Comment
Nebraska Public Power District	Yes	

3. Do you agree with the revisions proposed in PRC-024-1(X) to clarify (via footnotes 4 and 6) that Requirements R1 and R2 are applicable to both dispersed power producing resources identified through Inclusion I4 of the BES definition, as well as any aggregating equipment (potentially including non-BES equipment) from the individual resource up to the point of interconnection? If not, please provide technical rationale for your disagreement, along with suggested language changes.

Organization	Yes or No	Question 3 Comment
Dominion	No	It is Dominions understanding that these footnotes conflict with the IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems. Given possible changes to this standard are being actively discussed, Dominion suggests these footnotes not be included until the IEEE standard has implemented a conforming change.
MRO NERC Standards Review Forum	No	In order to provide relief for individual DGRs not being within compliance, the NSRF does recommend that perhaps there could be another set of VSLs established exclusively for DGRs. Case in point, if the entity finds one DGR that is not within the prescribed measures of Attachment 1 or 2, the entity would not be found non-compliant. Our recommendation would be for the Low VSL to >5% of DRGs were not within prescribed settings per Attachment 1 and 2 per of the aggregated Facility. This would allow a very small number of DGRs to have an issue. Or words to that affect. The NSRF believes this recommendation is aligned with the RAI program since one DGR (not within prescribed limits) will not impact the reliability of the BES.
DTE Electric	No	Please see our comment for Question 2.
Wisconsin Electric Power Company	No	We are concerned about the evidence required for dispersed power producing resources in measures M1 and M2. Since these devices are expected to be excluded from PRC-005, we will not be required to have calibration or maintenance records for evidence of compliance. We would like measures M1 and M2 of the standard to clearly state that evidence can be original design documents and no periodic testing or verification is required.

Organization	Yes or No	Question 3 Comment
Tacoma Public Utilties	No	The changes to PRC-024-1(X) include the applicability of the standard to Bulk Power System equipment that is not BES equipment. The purpose of the BES definition is to provide bright line applicability criteria for utilities to better understand which assets are subject to regulatory standards. The revision contained in PRC-024-1(X) deviate from the BES definition. If NERC would like to include Non-BES equipment in the regulatory standards then NERC should modify the BES definition to that end. Should Rationale for Footnotes 2 and 4 be changed to Rationale for Footnotes 4 and 6?
Alliant Energy	No	PRC-024-1X requirements R1 and R2 are using the terms “Protective Relaying” and “Protective Relay” with no definition provided for these terms within the NERC glossary of terms or within the standard itself. Footnote 3 is used to define how the term should be applied. The footnote suggests the previously undefined term “Protective Relaying” would be inclusive of any control equipment that contains protective functions. Although the footnote is only represented in standard PRC-024-01(X) and theoretically does not apply to other standards, it could introduce confusion in the other NERC standards that use these terms (e.g., if excitation controls are considered protective relaying under PRC-024, would they be considered as part of a protection system and require utilities to keep excitation control maintenance records under PRC-005?).
Nebraska Public Power District	No	In the Rationale for Footnotes 2 and 4, the phrase “including any non-Bulk Electric System collection system equipment” is used. We feel this statement and approach need to be removed because this standard revision hinges on Inclusion I4 of the BES Definition. It is overreaching to add non-BES equipment into a standard. The BES definition serves to identify what facilities are or are not applicable to NERC standards. We feel this adds back to the confusion that was to be avoided with the revised BES Definition.
Arizona Public Service Company	Yes	

Organization	Yes or No	Question 3 Comment
Northeast Power Coordinating Council	Yes	We agree with the revisions proposed in footnotes 4 and 6. However, frequency and voltage protective relays require coordination with other protective relays implemented elsewhere on the BES. However, PRC-001-1.1(X) Part 3.1 is excluding coordination of protective relays for Inclusion I4 which contradicts footnotes 4 and 6.
Corporate Compliance	Yes	Footnotes might be more clear if the language "....(potentially including non-BES equipment)..." were added.
PacifiCorp	Yes	
SERC PCS	Yes	
ACES Standards Collaborators	Yes	
SPP Standards Review Group	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	Yes	FE agrees that the PRC-024-1 standard in regard to NERC BES facilities I4 should apply to the voltage protective relays applied on the individual power producing resources, as well as voltage protective relays applied on equipment from the individual power producing resource up to the point of interconnection. However, we believe the SDT should make use of a Facilities Applicability section 4.2 as is done in many NERC standards such as PRC-019-2. By adding a section 4.2, it would avoid the need for the footnote approach and make it clearer that the standard is applicable to the dispersed generation equipment by simply evaluating the Applicability Section and having two subsections 4.1 Functional Entities and 4.2 Facilities. See FE comments to Question 4 for additional information.

Organization	Yes or No	Question 3 Comment
Seminole Electric Cooperative, Inc.	Yes	
David Kiguel	Yes	
American Electric Power	Yes	
Public Service Enterprise Group	Yes	
Ingleside Cogeneration LP	Yes	ICLP agrees that it makes sense to set the voltage and frequency ride-through settings consistently throughout a dispersed generation facility. We can think of no good technical reason to do otherwise. ICLP is concerned that an overly-enthusiastic CEA could assess a violation if a single relay record is missing among the thousands that would be covered by PRC-024-1(X), but agree that the RAI initiative has established an environment where a more reasonable compliance approach will be the norm.

4. Do you have any additional comments to assist the DGR SDT in further developing its recommendations?

Organization	Yes or No	Question 4 Comment
Arizona Public Service Company	No	
MRO NERC Standards Review Forum	No	
Corporate Compliance	No	
PacifiCorp	No	
SERC PCS	No	The comments expressed herein represent a consensus of the views of the above-named members of the SERC PCS only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
ACES Standards Collaborators	No	Thank you for the opportunity to comment.
Bonneville Power Administration	No	
DTE Electric	No	No comment.
Wisconsin Electric Power Company	No	
David Kiguel	No	
Public Service Enterprise Group	No	

Organization	Yes or No	Question 4 Comment
Tacoma Public Utilties	No	
Ingleside Cogeneration LP	No	
Alliant Energy	No	
Nebraska Public Power District	No	
Northeast Power Coordinating Council	Yes	Regarding PRC-024-1(X), the Rationale Box entitled Rationale for Footnotes 2 and 4 should be renamed Rationale for Requirement R1. Footnote 2 does not appear in R1, or on page 4 of the redline. The wording in the Rationale Box entitled Rationale for Footnotes 2 and 4 "...are set within the "no-trip zone" is confusing, as it could easily be interpreted to mean that relays should be set to trip within the "no-trip zone" which is a contradiction. Suggest rewording to "...are set such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the "no-trip zone"...".
Dominion	Yes	The language used to describe the Inclusion I4 resources is not consistent. For example:PRC-001 states "individual generating units," PRC-019 states "individual resources," and PRC-024 states "individual generating units and aggregating equipment." Dominion believes the language used in the standard revisions should be consistent with the Inclusion I4 definition. That is: a) The individual resources, and b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above
SPP Standards Review Group	Yes	We would suggest to the drafting team in reference to PRC-001-1.1(X) that you would evaluate adding the remaining Measures (M4, M5 and M6) to that particular section. Our concern would be that all the Measures Data pertaining to the Requirements has not been included and this has the potential of causing confusion on what evidence should be provided in an audit. Additionally, we would like the drafting team to

Organization	Yes or No	Question 4 Comment
		provide more clarity on the why there's a Rationale Box for Footnotes 2 and 4 in reference to PRC-024-1(X). Footnote 2 pertains to interchangeable terms which has been revised to align with the definition of the BES. If the drafting team's objective is to focus on Footnotes 4 and 6, we would suggest changing the header of the Rationale Box to read "Rationale for Footnotes 4 and 6". Finally, we would suggest to the drafting team adding Rationale Boxes to all three standards. We feel this would provide clarity to the industry on the expectations of the Requirements in the standards as well as promoting consistency with other documentation associated with this project.
FirstEnergy	Yes	FE suggests the standard drafting team give consideration for making consistent use of Section 4 to include both a sub-section 4.1 Functional Entities and 4.2 Facilities. This would alleviate the need to bury pertinent information and clarity around what facilities are in scope within footnotes. Currently only PRC-019 includes both of these applicability sub-sections and they should be used in each standard. The sections may need to be written differently in each of the three standards but should be used in each. Furthermore, standard PRC-019-2 which currently uses sub-section 4.2 Facilities includes text that is simply repeats of what is stated in NERC BES Inclusion statement I2 which could be revised/simplified. As an example, FE believes that section 4 of PRC-019-2 could be written as follows:4 Applicability 4.1 Functional Entities 4.1.1 Generator Owner 4.1.2 Transmission Owner 4.2 Facilities 4.2.1 Generator Owner - for the purpose of this standard, the term, "applicable Facility" shall mean NERC BES Definition Inclusion I2 and I4. Where voltage regulating control for the BES generation facility is performed solely at the individual resources, those facilities are also included. 4.2.2 Transmission Owner - for the purpose of this standard, the term, "applicable Facility" shall mean a synchronous condenser that is a qualifying BES facility under NERC BES Definition Inclusion I5.As another example, standard PRC-001-1.1 could be written as follows:4 Applicability 4.1 Functional Entities 4.1.1 Balancing Authorities 4.1.2 Transmission Operators 4.1.3 Generator Operators 4.2 Facilities 4.2.1 - This standard applies to all Transmission Elements operated at 100 kV or higher and Real Power and Reactive

Organization	Yes or No	Question 4 Comment
		Power resources connected at 100 kV or higher as clarified by the NERC BES definition Inclusion statements. In regard to Inclusion I4 this standard is not applicable to the individual generating units of dispersed power producing resources. One additional suggestion: Lastly, throughout the various standards there is a footnote indicating "The terms 'dispersed generation resources' and 'dispersed power producing resources' are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES." It appears this footnote is for informational purposes only during the development of standard and will be removed in the final clean version. If that is not the case, consider the need for a NERC Glossary of Term for Dispersed Generation Resource that would indicate it is synonymous with the NERC BES Definition in regard to Inclusion statement I4 for dispersed power producing resources.
Seminole Electric Cooperative, Inc.	Yes	
American Electric Power	Yes	The comment form states in part "Because two of the medium-priority standards have recently been revised or are undergoing revision in another current project..." In addition, the redline version of the standard states "Given the timing of concurrent standards development of PRC projects, PRC-024-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-024." Both these comments infer that at least one other current project impacts PRC-024, but we cannot determine which project(s) that is. Could you provide some clarity on that?

Additional Comments:
MS Energy
Lance Bean

PRC-001-1.1(X)

- In the new bullet item of R3.1, the standards drafting team refers to individual "generating units". The BES definition Inclusion I4 includes the individual "resources". In PRC-001-1.1(X), would it make sense to replace "generating units" with "resources" to be consistent with the BES definition?

PRC-024-1(X)

- Ahead of the Introduction, there is a statement "the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard". The text box is not in the Applicability section, it is in B. Requirements, R1.
- The text box title is "Rationale for Footnotes 2 and 4". The two new footnotes are 4 and 6. I assume footnotes 1 & 2 will be removed once the Standard is approved, so perhaps the existing title is acceptable.
- The text box refers to individual "generating units". I think "generating units" should be changed to "resources".
- The text box also includes the text "it is appropriate to require that protective relay settings…are set within the no-trip zone". I think the statement should be "it is appropriate to require that protective relay settings…are **not** set within the no-trip zone"

END OF REPORT

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project 2014-01 Standards Applicability for Dispersed Generation Resources

The Project 2014-01 Drafting Team thanks all commenters who submitted comments on the standard. These standards were posted for a 45-day public comment period from November 5, 2014 through December 23, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 25 sets of comments, including comments from approximately 98 different people from approximately 69 companies representing all 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

This document contains the Project 2014-01 Standards Applicability for Dispersed Generation Resources (DGR) standard drafting team's (SDT) response to all industry comments received during this comment period. The DGR SDT encourages commenters to review its responses to ensure all concerns have been addressed. The DGR SDT notes that a significant majority of commenters agree with the DGR SDT's recommendations on the standards, but that several commenters expressed specific concerns. Some comments supporting the DGR SDT's recommendations are discussed below but in most cases are not specifically addressed in this response. Also, several comments in response to specific questions are duplicated in other questions, and several commenters raise substantively the same concerns as others. Therefore, the DGR SDT's consideration of all comments is addressed in this section in summary form, with duplicate comments treated as a single issue. Any comments made on another standard are addressed in the DGR SDT's response to comments on that standard.

1. Summary Consideration

Based on the results from the recent comment and ballot period, it appears that industry overwhelmingly agrees with the DGR SDT's recommendations on applicability changes to PRC-001; PRC-019; and PRC-024, to account for the unique characteristics of dispersed power producing resources[1] in the standards. However, there are some disagreements among stakeholders and suggestions for language revisions contained in industry comments. To the extent that there are comments beyond the scope of this SDT, those comments will be communicated to the appropriate team for consideration.

[1] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

The DGR SDT has carefully reviewed and considered each stakeholder comment and has revised its recommendations where suggested changes improve clarity and are consistent with DGR SDT intent and apparent industry consensus. Several commenters suggested non-substantive language changes for standard language as well as explanatory language, such as language in particular rationale boxes. The DGR SDT has carefully considered each comment and has implemented revisions as ~~appropriate~~follows:

- The DGR SDT made non-substantive revisions to the align the terms referring to individual generating units of the dispersed power producing resources in PRC-001; PRC-019; and PRC-024 with one another.
- The DGR SDT revised the language in the Description of Current Draft section of PRC-001; PRC-019; and PRC-024 and PRC-001 the standard, as well as similar language in the standard's Implementation Plan to reflect that there are not any other current projects seeking to revise those standards.

~~. However,~~ Aall recommended changes are non-substantive as contemplated by the NERC Standard Processes Manual and therefore do not require an additional ballot. The DGR SDT's consideration of all comments follows.

2. General Comments

At least one commenter recommended that the language describing individual generating units in PRC-001; PRC-019; and PRC-024 should be aligned with one another. The DGR SDT agrees and has therefore made non-substantive revisions to the terms to provide consistency of language among the recommended modifications.

At least one commenter requested that the DGR SDT consider the need for a NERC Glossary term for dispersed generation resource that would indicate it is synonymous with the NERC BES Definition in regard to Inclusion statement I4 for dispersed power producing resources to address the information contained in the footnote in the standard that indicates "the terms 'dispersed generation resources' and 'dispersed power producing resources' are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES." The DGR SDT expects the use of the terms will be transitional, and that the term used in the NERC BES definition, as included in the Glossary of Terms Used in NERC Reliability Standards, will be the only term used to refer to dispersed generation resources on a going forward basis.

At least one commenter noted that the comment form states in part "because two of the medium-priority standards have recently been revised or are undergoing revision in another current project...," and that additionally, the redline version of the standard states "given the timing of concurrent standards development of PRC projects, PRC-024-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-024," but that they were unable to determine another project seeking to

revise the standard. The DGR SDT agrees that there are not any other current projects seeking to revise PRC-024, and has revised the language in the Description of Current Draft section of the standard, as well as similar language in the standard's Implementation Plan.

3. PRC-001

At least one commenter suggested that the applicability sections should be modified to limit applicability of the requirements, rather than using "sub-bullets." The SDT maintains that the approach of utilizing "sub-bullets" to change applicability has been supported by NERC staff during modification of this and other standards, and it is the position of the SDT that the current modification allows specific requirements to be targeted as needed, and that this approach appears to be overwhelmingly supported by the majority of the industry as evidenced by the submitted responses. Therefore, the DGR SDT declines to adopt this suggestion.

One commenter suggested that the standards should require an assessment of whether coordination must be performed jointly by the TOP and the GOP as an alternative to the DGR SDT's suggested changes. Additional coordination is not precluded by the revised standard. Adding a further requirement to jointly assess the necessity of coordination between the TOP, host BA, and the GOP is beyond the scope of the DGR SDT. It is the DGR SDT's position that the proposed revisions to the standard adequately support reliability and are consistent with current practices. Therefore, the SDT declines to adopt this suggestion.

At least one commenter expressed concern that there may be situations where the TOP should be informed of the upstream protection settings associated with failure of an individual generator Protection System or breaker to operate, and also suggested that the coordination of Protections Systems between GOs and TOs is the subject of Project 2007-06 - System Protection Coordination, and requested that the DGR SDT communicate their comments to that team so they may address them in their project as they determine appropriate. While the DGR SDT's position will be communicated to the Project 2007-06 SDT, there is a need to address PRC-001 directly as this is still the effective standard. In the proposed modification, the "upstream protection systems," that are at the point of aggregation of 75 MVA or greater are still in scope for dispersed power producing resources, and as such, will be coordinated with the TOP and host BA.

At least one commenter requested the drafting team clarify that R3.1 still requires system protection coordination for generating units covered by I4 of the BES definition, but that the coordination can take place at the aggregation or interconnection point, rather than at the individual unit level. Also, another commenter expressed concern that R3.1 only excludes individual generator protection equipment from coordinating with the host BA and TOP, and stated that, similarly, the applicability of Requirements R1, R2.1, and R5.1 should be limited to aggregation points greater than 75 MVA. The DGR SDT maintains that the proposed requirements of the standard adequately support reliability and are consistent with current practices. The proposed modifications to the standard limit the requirements to protective systems associated with the facilities at the point of aggregation of 75 MVA or greater (i.e. substation level protection systems). The applicability for Requirements R1 and R2.1 are explained in the White Paper. The DGR SDT has determined that the language; "that could require changes in the protection systems of others" adequately limits the scope of requirement R5.1.

One commenter requested that the DGR SDT consider adding Measures to Requirements R4, R5, and R6 of PRC-001; however, addressing Measures for which the DGR SDT did not modify the associated Requirement is beyond the scope of the DGR SDT's SAR.

4. PRC-019

At least one commenter suggested that individual generating units of dispersed power producing resources should be completely exempt from PRC-019's requirements, noting the similarity to the exemption in PRC-001-1.1(~~x~~ii). Similarly, a commenter stated that applying the standard to the individual wind turbine level is inconsistent with the revisions to PRC-001, PRC-004 and VAR-002. It is the position of the DGR SDT that it is necessary to coordinate voltage regulating controls with the TOP and in the case where voltage control is solely accomplished at the individual unit level, the individual units should be included in the scope of this standard. The DGR SDT has maintained a consistent approach to its recommendations. The DGR SDT maintains that the standard should be applied at the individual unit level, as stated in 4.2.3.1., in order to accomplish the objective of the standard.

At least one commenter expressed concern that the applicability of PRC-019-2 excludes voltage regulating controllers serving a multiplicity of individual generating units with a combined capacity less than 75 MVA. The DGR SDT understands the comment to refer to voltage regulating control at the generating plant/Facility level of BES generators identified through inclusion I4 of the BES definition; however, the revisions to the standard proposed by the DGR SDT expanded the applicability from voltage regulating control at the plant/Facility level, such as voltage controllers serving a multiplicity of individual generating units, to also include individual generating units.

5. PRC-024

At least one commenter suggested that the footnotes conflict with the IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems and suggested the footnotes should not be included until the IEEE standard has implemented a conforming change. It is the position of the SDT that addressing IEEE 1547 is beyond the scope of the SDT, as it is not referenced in PRC-024.

At least one commenter suggested the DGR SDT consider including the following sub-sections: 4.1 Functional Entities and 4.2 Facilities rather than using footnotes; however, using a footnote to revise applicability has been supported by NERC staff during modification of this standard. The SDT therefor believes the proposed modification is satisfactory and thus declines to incorporate the suggested modification.

At least one commenter recommended establishing another set of VSLs established exclusively for DGRs. The DGR SDT agrees that the magnitude of the reliability impact of an individual DGR unit with non-compliant settings should be addressed; however, it is the position of the DGR SDT that this issue

is better addressed during the compliance enforcement process. Further, risk assessments performed during RAI should address this issue. The DGR SDT believes the nature of the requirements of Requirements R1 and R2 lend themselves for a pass/fail VSL; therefore, designing a range of severity of non-compliance is inappropriate based on VSL guidelines.

At least one commenter requested that Measures M1 and M2 of the standard clearly state that evidence can be original design documents and no periodic testing or verification is required. The SDT does not see a need to specify what evidence is acceptable strictly for dispersed power producing resources. The SDT believes that the existing use of "evidence" is broad enough to capture the commenter's intent.

At least one commenter stated that the changes to PRC-024-1(X) include the applicability of the standard to Bulk Power System equipment that is not BES equipment, and indicated that the BES definition should be modified to include non-BES equipment in the regulatory standards rather than particular standards. Similarly, one commenter suggested that the language "including any non-Bulk Electric System collection system equipment" should be omitted from the rationale for footnotes 2 and 4, because the BES definition serves to identify what facilities are or are not applicable to NERC standards.
Reliability standards may apply to specific equipment characteristics, which may include equipment not included through the BES definition. It is not in the DGR SDT's scope of work to modify the definition of BES.

At least one commenter suggested that the language in the Rationale Box entitled Rationale for Footnotes 2 and 4 "...are set within the "no-trip zone" is confusing and should be revised. The DGR SDT provided clarifying language.

At least one commenter expressed concern that the use of the terms "Protective Relaying" and "Protective Relay" in Requirements R1 and R2 may introduce confusion in other standards that use the same or similar terms, since, although footnote 3 provides further information about the term, a definition of the terms is not provided in the standard or in the Glossary of Terms Used in NERC Reliability Standards. The terms "protective relaying" and "protective relay" are not capitalized, and are not defined terms as used in Requirements R1 and R2, nor are the terms capitalized or used as defined terms in footnote 3; therefore the use of the terms in this standard have no bearing on the use of the same or similar terms in other standards. The requirement language and footnote 3 address aspects of the standard that were in the previously approved version and not associated with the applicability of dispersed power producing resources, as such revisions to these items are not in the scope of the SDT DGR's SAR to change.

At least one commenter expressed agreement with the revisions proposed in footnotes 4 and 6, but noted that frequency and voltage protective relays require coordination with other protective relays

implemented elsewhere on the BES, and expressed concern that PRC-001-1.1(~~X~~ii) Part 3.1 is excluding coordination of protective relays for Inclusion I4 which contradicts footnotes 4 and 6. While PRC-001-1.1(~~x~~ii) excludes coordination of new or changes to existing relays with the TOP and host BA, PRC-024 still requires that these relays be set respecting the "no-trip zone." The SDT does not believe there is a contradiction as the PRC standards address different compliance aspects associated with these relays. Further, PRC-024 Requirement R4 requires the reporting of such relay settings to the TP and PC.

At least one commenter suggested revising the language of the footnotes to add ". . . (potentially including non-BES equipment)..." Thank you for your comment. It is the SDT's position that the language of the footnote as drafted is sufficiently clear and unambiguous.

At least one commenter agreed that the PRC-024-1 standard in regard to NERC BES facilities I4 should apply to the voltage protective relays applied on the individual power producing resources, as well as voltage protective relays applied on equipment from the individual power producing resource up to the point of interconnection. However, the commenter expressed that the SDT should make use of a Facilities Applicability section 4.2 as is done in many NERC standards such as PRC-019-2 rather than using a footnote. The approach of utilizing the footnote to revise applicability has been supported by NERC staff members during modification of this standard. The SDT believes the proposed modification is satisfactory and thus declines to incorporate the suggested modification.

At least one commenter agreed that it is sensible to set the voltage and frequency ride-through settings consistently throughout a dispersed generation facility: however, the commenter expressed concern that a violation may be assessed if a single relay record is missing among the potentially thousands of relays that would be covered by PRC-024-2~~1(X)~~. The commenter went on to note that they agree that the RAI initiative has established an environment where a more reasonable compliance approach will be the norm. How violations are processed by NERC compliance is not in the purview of the DGR SDT.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[2]

[2] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

1. **Do you agree with the revisions proposed in PRC-001-1.1(X) Requirement R3 part 3.1 to exclude the individual generating units of dispersed power producing resources identified through Inclusion I4 of the BES definition from this requirement? If not, please provide technical rationale for your disagreement, along with suggested language changes.** 15
2. **Do you agree with the revisions proposed in the Facilities section of proposed PRC-019-2 to clarify that the standard is applicable to dispersed power producing resources identified through Inclusion I4 of the BES definition where voltage regulating contol for the facility is performed solely at the individual resource? If not, please provide technical rationale for your disagreement, along with suggested language changes.** 19
3. **Do you agree with the revisions proposed in PRC-024-1(X) to clarify (via footnotes 4 and 6) that Requirements R1 and R2 are applicable to both dispersed power producing resources identified through Inclusion I4 of the BES definition, as well as any aggreating equipment (potentially including non-BES equipment) from the individual resource up to the point of interconnection? If not, please provide technical rationale for your disagreement, along with suggested language changes.** 23
4. **Do you have any additional comments to assist the DGR SDT in further developing its recommendations?**....27

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Kristie Cocco	Arizona Public Service Company			X		X	X				
N/A													
2.	Group	Guy Zito	Northeast Power Coordinating Council										X

.

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Kathleen Goodman	ISO - New England	NPCC	2

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

8.	Michael Jones	National Grid	NPCC	1
9.	Mark Kenny	Northeast Utilities	NPCC	1
10.	Helen Lainis	Independent Electricity Suystem Operator	NPCC	2
11.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
12.	Bruce Metruck	New York Power Authority	NPCC	6
13.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
14.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
21.	Brian Shanahan	National Grid	NPCC	1
22.	Wayne Sipperly	New York Power Authority	NPCC	5
23.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5

3.	Group	Connie Low	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Randi Heise	NERC Compliance Policy	NPCC	5
2.	Louis Slade	NERC Compliance Policy	SERC	1, 3, 5, 6
3.	Larry Nash	Electric Transmission	SERC	
4.	Chip Humphrey	Power Generation Compliance	NPCC	5
5.	Louis Slade	NERC Compliance Policy	RFC	5, 6

4.	Group	Joe DePoorter	MRO NERC Standards Review Forum	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Amy Casucelli	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power Company	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative, Inc.	MRO	1, 2, 5, 6
4.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jenson	Western Area Power Administration	MRO	1, 6

Group/Individual		Commenter	Organization		Registered Ballot Body Segment									
					1	2	3	4	5	6	7	8	9	10
7.	Joseph DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6										
8.	Ken Goldsmith	Alliant Energy	MRO	4										
9.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6										
10.	Marie Knox	Midwest ISO Inc.	MRO	2										
11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6										
12.	Randi Nyholm	Minnesota Power	MRO	1, 5										
13.	Scott Nickels	Rochester Public Utilities	MRO	4										
14.	Terry Harbour	MidAmerican Energy COmpany	MRO	1, 3, 5, 6										
15.	Tom Breene	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6										
16.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5										
5.	Group	Dianne Gordon	Corporate Compliance		X		X		X					
N/A														
6.	Group	Sandra Shaffer	PacifiCorp							X				
N/A														
7.	Group	David Greene	SERC PCS											X

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Miller	GTC	SERC	1
2.	Paul Nauert	Ameren	SERC	1, 3
3.	Greg Davis	GTC	SERC	1
4.	James Evans	SCE&G	SERC	1, 3, 5, 6
5.	Steve Edwards	Dominion	SERC	1, 3, 6
6.	George Pitts	TVA	SERC	1, 3, 5, 6

8.	Group	Jason Marshall	ACES Standards Collaborators							X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bob Solomon	Hoosier Energy	RFC	1
2.	Paul Jackson	Buckeye Power	RFC	3, 4, 5
3.	Scott Brame	North Carolina Electric Membership Corporation	SERC	3, 4, 5
4.	Ginger Mercier	Prairie Power	SERC	3
5.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
6.	Chip Koloini	Golden Spread Electric Cooperative	ERCOT	3, 5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
9.	Group	Shannon V. Mickens	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	john falsey	Invenergy LLC	NA - Not Applicable	NA
2.	Stephanie Johnson	Westar Energy, Inc.	SPP	1, 3, 5, 6
3.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
4.	Luis Zaragoza	Sunflower Electric Power Corporation	SPP	1
5.	James Nail	City of Independence, Missouri	SPP	3, 5
6.	Jonathan Hayes	Southwest Power Pool	SPP	2
7.	Robert Rhodes	Southwest Power Pool	SPP	2
8.	Shannon Mickens	Southwest Power Pool	SPP	2

10.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Steve Enyeart	Customer Service Engineering	WECC	1

11.	Group	Doug Hohlbaugh	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Smith	FE - RBB - Seg 1	RFC	1
2.	Rich Hoag	FE - RBB - Seg 3	RFC	3
3.	Doug Hohlbaugh	FE - RBB - Seg 4	RFC	4
4.	Ken Dresner	FE - RBB - Seg 5	RFC	5
5.	Kevin Querry	FE - RBB - Seg 6	RFC	6
6.	Phil Bowers	FE - TO SME	RFC	1
7.	Bill Duge	FE - GO SME	RFC	5
8.	Rusty Loy	FE - GO SME	RFC	5
9.	Steve Wittenauer	FE - TO SME	RFC	1

12.	Group	Kathleen Black	DTE Electric			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kent Kujala	NERC Compliance	RFC	3
2.	Daniel Herring	NERC Training & Standards Development	RFC	4
3.	Mark Stefaniak	Merchant Operations	RFC	5
4.	Neil Kennings	Renewable Energy		

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
5. Barbara Scramlin		DO SOC											
13.	Individual	John Falsey	Invenergy LLC					X					
14.	Individual	John Falsey	Invenergy LLC					X					
15.	Individual	Barbara Kedrowski	Wisconsin Electric Power Company			X	X	X					
16.	Individual	David Jendras	Ameren	X		X		X	X				
17.	Individual	Maryclaire Yatsko	Seminole Electric Cooperative, Inc.	X		X	X	X	X				
18.	Individual	David Kiguel	David Kiguel								X		
19.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
20.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
21.	Individual	Michael Hill	Tacoma Public Utilties	X		X	X	X	X				
22.	Individual	Michelle R. DAntuono	Ingleside Cogeneration LP					X					
23.	Individual	Larry Heckert	Alliant Energy				X						
24.	Individual	Venona Greaff	Occidental Chemical Corporation							X			
25.	Individual	Jamison Cawley	Nebraska Public Power District	X		X		X					

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

~~**Summary Consideration:**~~

Organization	Agree	Supporting Comments of "Entity Name"
Invenergy LLC	Agree	Southwest Power Pool
Ameren	Agree	We agree with and adopt the SERC PCS comments for Project 2014-01.
Occidental Chemical Corporation	Agree	Ingleside Cogeneration, LP

1. **Do you agree with the revisions proposed in PRC-001-1.1(X) Requirement R3 part 3.1 to exclude the individual generating units of dispersed power producing resources identified through Inclusion I4 of the BES definition from this requirement? If not, please provide technical rationale for your disagreement, along with suggested language changes.**

~~**Summary Consideration:**~~

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	Although outside of the scope of the work of this Drafting Team, R3.1, as well as all Parts of this standard should be identified as 3.1, etc., and the wording in the added text made consistent with NERC format preferences. Requirement R3.1 should be Part 3.1. Because this is a format change, it should be able to be incorporated in this revision. Also outside the scope of the SAR would be a revision to the Applicability. This standard is not applicable to the Balancing Authority and Host Balancing Authority. Protective system in R3 and Part 3.1 should be replaced with the defined term Protection System. The reference to protective system in the Rationale for Applicability Exclusion in Requirement R3.1 should be revised accordingly.
ACES Standards Collaborators	No	While we agree with the concepts and intent to exclude applicability of sub-requirement R3.1 to the individual units of dispersed power producing resources, we do not believe the actual implementation is correct. In an August 10, 2009 informational filing, NERC indicated to the Commission that they would use bulleted lists to indicate when "components may reflect a list of options that may be undertaken to achieve compliance." Thus, we do not see how a sub-bullet of a sub-requirement can be used to change the applicability of the requirement. We believe the applicability section should be modified to limit applicability of the requirement.

Organization	Yes or No	Question 1 Comment
David Kiguel	No	It should be recognized that there might be cases (though rare) where coordination is actually required. Rather than removing applicability of Requirement 3.1 altogether, the standard should require that an assessment of whether coordination is required be performed jointly by the TOP and the GOP. The assessment should address any involved BES elements. If the conclusion of the assessment is that no coordination in required for certain parts of the protections, then and only then, such coordination can be omited.
Public Service Enterprise Group	No	We object to part 3.1 for two reasons: First, individual dispersed resources connected to a collector system will have a protection system and breaker for each generator to isolate them for a fault on the generator-side of that breaker. In the event any individual dispersed resource Protection System or associated breaker fails, the upstream Protection System will need open the main breaker to isolate the fault. The TOP needs to be informed of the upstream protection setting associated with failure an individual generator Protection System or breaker to operate. Second, the coordination of Protections Systems between GOs and TOs is the subject of Project 2007-06 - System Protection Coordination, and Project 2014-01's SDT should send their concerns to this team so they may address them in their project.
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP (ICLP) believes that the project team's intent in R3.1 is to ensure that only the Protection Systems corresponding to 75+ MVA points of aggregation are applicable, but is not comfortable that the proposed update captures that point. In fact, it seems to only exclude those components protecting individual solar panels/windmills from the requirement to coordinate new deployments and modifications with the BA and TOP. In our view, the intermediate aggregation points less than 75 MVA are of no practical interest to the BA and TOP - and should be specifically excluded from the requirement. Similarly, the applicability of

Organization	Yes or No	Question 1 Comment
		Requirements R1, R2.1, and R5.1 should be limited to 75+ MVA aggregation points. Protection System awareness, failures that "reduce system reliability", and changes in operating conditions that may affect a TOP's Protection System are only meaningful at those capacity levels. In fact, if too much attention is placed on large numbers of very low-impact systems, there will less consideration made for those that really do present a risk to the BES.
Arizona Public Service Company	Yes	
Dominion	Yes	
MRO NERC Standards Review Forum	Yes	
Corporate Compliance	Yes	
PacifiCorp	Yes	
SERC PCS	Yes	
SPP Standards Review Group	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	Yes	While FirstEnergy (FE) agrees with the exclusion, it should not simply be left to inference that the remainder of the standard does apply to the I4 units at the collector or interconnection point. See FE comments to Question 4 for our suggested approach to add clarity.
DTE Electric	Yes	

Organization	Yes or No	Question 1 Comment
Wisconsin Electric Power Company	Yes	
Seminole Electric Cooperative, Inc.	Yes	Seminole requests the drafting team to clarify that R3.1 still requires system protection coordination for generating units covered by I4 of the BES definition, however, that this coordination can take place at the aggregation or interconnection point, instead of at the individual unit.
American Electric Power	Yes	The last sentence in the rationale box, "...do not need to be coordinated with the transmission protective systems, as this coordination would not provide reliability benefits to the BES" might be better stated as "...do not need to be coordinated directly with the transmission protective systems due to the intervening collector system(s)."
Tacoma Public Utilties	Yes	
Alliant Energy	Yes	
Nebraska Public Power District	Yes	
Invenergy LLC		

2. Do you agree with the revisions proposed in the Facilities section of proposed PRC-019-2 to clarify that the standard is applicable to dispersed power producing resources identified through Inclusion I4 of the BES definition where voltage regulating control for the facility is performed solely at the individual resource? If not, please provide technical rationale for your disagreement, along with suggested language changes.

~~**Summary Consideration:**~~

Organization	Yes or No	Question 2 Comment
Arizona Public Service Company	No	The individual generating unit of a dispersed power producing resources has negligible impact on BES performance and should be completely exempt from this requirement in PRC-019, very similar to exemption in PRC-001-1.1(x). Making the standard applicable to individual disperse power producing unit is inappropriate use of the limited resources.
Dominion	No	Dominion does not believe the addition of 4.2.3.1 is necessary and, in fact introduces ambiguity. Some here read this addition as inferring that, only if the voltage control is applied at the individual resource (as identified in BES I4) would 4.2.3 apply to dispersed power producing resources. If SDT decides to retain, we suggest it be modified to state "This would also include voltage regulating controls that are performed solely at the individual resources dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition."
ACES Standards Collaborators	No	We do not oppose applicability of PRC-019 to the individual dispersed power producing resources where voltage regulating control is performed at the individual unit. However, the proposed changes do not accomplish this and actually only serve to confuse the applicability of the standard. All NERC standards are applicable to individual Elements of the BES definition. Since the BES definition includes the individual units of dispersed power producing resource, PRC-019-2 is applicable to those units. Adding sub-section 4.2.3.1 that states this includes "individual dispersed

Organization	Yes or No	Question 2 Comment
		power producing resources... where voltage regulating control for the facility is performed solely at the individual resources" does not add these Elements as they were already included. Furthermore, it does not exclude those individual dispersed power producing resources where voltage regulating control is performed at the aggregate level. The bottom line is that the rationale that is explained in the standard is not accomplished by this change. We believe this standard does not require modification to include "individual dispersed power producing resources... where voltage regulating control for the facility is performed solely at the individual resources" as these resources are already included. However, an explanation in the application guidelines section of the standard is warranted to explain the applicability.
DTE Electric	No	This standard applies at the individual wind turbine level which is inconsistent with the revisions to PRC-001, PRC-004 and VAR-002, where the standards only apply where there is 75 MVA connected at 100kV or higher.
Ingleside Cogeneration LP	No	ICLP believes that the way that the applicability criteria in PRC-019-2 has been re-framed only includes voltage regulating controls at the single dispersed unit level and at aggregation points at 75 MVA or greater. This omits those voltage controllers serving an entire string of wind mills or solar panels with combined capacity less than 75 MVA. We do not think that was the drafting team's intent, and suggest that the language be clarified.
Northeast Power Coordinating Council	Yes	
MRO NERC Standards Review Forum	Yes	

Organization	Yes or No	Question 2 Comment
Corporate Compliance	Yes	A possible edit would be to change 4.2.3.1 (regarding individual dispersed gen units) to 4.2.4. This may make the meaning of types of "Applicable Facilities" more clear to the reader.
PacifiCorp	Yes	
SERC PCS	Yes	If it is the intention of the SDT to exclude individual dispersed power producing resources from the list of Applicable Facilities when voltage regulating control is not performed solely at the individual resources, we suggest that the SDT include the word “only” in R4.2.3.1. “This includes individual dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition only where voltage regulating control for the facility is performed solely at the individual resources”
SPP Standards Review Group	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	Yes	See FE comments to Question 4.
Wisconsin Electric Power Company	Yes	
Seminole Electric Cooperative, Inc.	Yes	
David Kiguel	Yes	
American Electric Power	Yes	

Organization	Yes or No	Question 2 Comment
Public Service Enterprise Group	Yes	
Tacoma Public Utilties	Yes	
Alliant Energy	Yes	
Nebraska Public Power District	Yes	

3. Do you agree with the revisions proposed in PRC-024-1(X) to clarify (via footnotes 4 and 6) that Requirements R1 and R2 are applicable to both dispersed power producing resources identified through Inclusion I4 of the BES definition, as well as any aggregating equipment (potentially including non-BES equipment) from the individual resource up to the point of interconnection? If not, please provide technical rationale for your disagreement, along with suggested language changes.

~~**Summary Consideration:**~~

Organization	Yes or No	Question 3 Comment
Dominion	No	It is Dominions understanding that these footnotes conflict with the IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems. Given possible changes to this standard are being actively discussed, Dominion suggests these footnotes not be included until the IEEE standard has implemented a conforming change.
MRO NERC Standards Review Forum	No	In order to provide relief for individual DGRs not being within compliance, the NSRF does recommend that perhaps there could be another set of VSLs established exclusively for DGRs. Case in point, if the entity finds one DGR that is not within the prescribed measures of Attachment 1 or 2, the entity would not be found non-compliant. Our recommendation would be for the Low VSL to >5% of DRGs were not within prescribed settings per Attachment 1 and 2 per of the aggregated Facility. This would allow a very small number of DGRs to have an issue. Or words to that affect. The NSRF believes this recommendation is aligned with the RAI program since one DGR (not within prescribed limits) will not impact the reliability of the BES.
DTE Electric	No	Please see our comment for Question 2.
Wisconsin Electric Power Company	No	We are concerned about the evidence required for dispersed power producing resources in measures M1 and M2. Since these devices are expected to be excluded from PRC-005, we will not be required to have calibration or maintenance records for

Organization	Yes or No	Question 3 Comment
		evidence of compliance. We would like measures M1 and M2 of the standard to clearly state that evidence can be original design documents and no periodic testing or verification is required.
Tacoma Public Utilties	No	The changes to PRC-024-1(X) include the applicability of the standard to Bulk Power System equipment that is not BES equipment. The purpose of the BES definition is to provide bright line applicability criteria for utilities to better understand which assets are subject to regulatory standards. The revision contained in PRC-024-1(X) deviate from the BES definition. If NERC would like to include Non-BES equipment in the regulatory standards then NERC should modify the BES definition to that end. Should Rationale for Footnotes 2 and 4 be changed to Rationale for Footnotes 4 and 6?
Alliant Energy	No	PRC-024-1X requirements R1 and R2 are using the terms "Protective Relaying" and "Protective Relay" with no definition provided for these terms within the NERC glossary of terms or within the standard itself. Footnote 3 is used to define how the term should be applied. The footnote suggests the previously undefined term "Protective Relaying" would be inclusive of any control equipment that contains protective functions. Although the footnote is only represented in standard PRC-024-01(X) and theoretically does not apply to other standards, it could introduce confusion in the other NERC standards that use these terms (e.g., if excitation controls are considered protective relaying under PRC-024, would they be considered as part of a protection system and require utilities to keep excitation control maintenance records under PRC-005?).
Nebraska Public Power District	No	In the Rationale for Footnotes 2 and 4, the phrase "including any non-Bulk Electric System collection system equipment" is used. We feel this statement and approach need to be removed because this standard revision hinges on Inclusion I4 of the BES Definition. It is overreaching to add non-BES equipment into a standard. The BES definition serves to identify what facilities are or are not applicable to NERC

Organization	Yes or No	Question 3 Comment
		standards. We feel this adds back to the confusion that was to be avoided with the revised BES Definition.
Arizona Public Service Company	Yes	
Northeast Power Coordinating Council	Yes	We agree with the revisions proposed in footnotes 4 and 6. However, frequency and voltage protective relays require coordination with other protective relays implemented elsewhere on the BES. However, PRC-001-1.1(X) Part 3.1 is excluding coordination of protective relays for Inclusion I4 which contradicts footnotes 4 and 6.
Corporate Compliance	Yes	Footnotes might be more clear if the language "....(potentially including non-BES equipment)..." were added.
PacifiCorp	Yes	
SERC PCS	Yes	
ACES Standards Collaborators	Yes	
SPP Standards Review Group	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	Yes	FE agrees that the PRC-024-1 standard in regard to NERC BES facilities I4 should apply to the voltage protective relays applied on the individual power producing resources, as well as voltage protective relays applied on equipment from the individual power producing resource up to the point of interconnection. However, we believe the SDT should make use of a Facilities Applicability section 4.2 as is done in many NERC standards such as PRC-019-2. By adding a section 4.2, it would avoid the need for the

Organization	Yes or No	Question 3 Comment
		footnote approach and make it clearer that the standard is applicable to the dispersed generation equipment by simply evaluating the Applicability Section and having two subsections 4.1 Functional Entities and 4.2 Facilities. See FE comments to Question 4 for additional information.
Seminole Electric Cooperative, Inc.	Yes	
David Kiguel	Yes	
American Electric Power	Yes	
Public Service Enterprise Group	Yes	
Ingleside Cogeneration LP	Yes	ICLP agrees that it makes sense to set the voltage and frequency ride-through settings consistently throughout a dispersed generation facility. We can think of no good technical reason to do otherwise. ICLP is concerned that an overly-enthusiastic CEA could assess a violation if a single relay record is missing among the thousands that would be covered by PRC-024-1(X), but agree that the RAI initiative has established an environment where a more reasonable compliance approach will be the norm.

4. Do you have any additional comments to assist the DGR SDT in further developing its recommendations?

~~**Summary Consideration:**~~

Organization	Yes or No	Question 4 Comment
Arizona Public Service Company	No	
MRO NERC Standards Review Forum	No	
Corporate Compliance	No	
PacifiCorp	No	
SERC PCS	No	The comments expressed herein represent a consensus of the views of the above-named members of the SERC PCS only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
ACES Standards Collaborators	No	Thank you for the opportunity to comment.
Bonneville Power Administration	No	
DTE Electric	No	No comment.
Wisconsin Electric Power Company	No	

Organization	Yes or No	Question 4 Comment
David Kiguel	No	
Public Service Enterprise Group	No	
Tacoma Public Utilties	No	
Ingleside Cogeneration LP	No	
Alliant Energy	No	
Nebraska Public Power District	No	
Northeast Power Coordinating Council	Yes	Regarding PRC-024-1(X), the Rationale Box entitled Rationale for Footnotes 2 and 4 should be renamed Rationale for Requirement R1. Footnote 2 does not appear in R1, or on page 4 of the redline. The wording in the Rationale Box entitled Rationale for Footnotes 2 and 4 "...are set within the "no-trip zone" is confusing, as it could easily be interpreted to mean that relays should be set to trip within the "no-trip zone" which is a contradiction. Suggest rewording to "...are set such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the "no-trip zone"...".
Dominion	Yes	The language used to describe the Inclusion I4 resources is not consistent. For example:PRC-001 states "individual generating units," PRC-019 states "individual resources," and PRC-024 states "individual generating units and aggregating equipment." Dominion believes the language used in the standard revisions should be consistent with the Inclusion I4 definition. That is: a) The individual resources, and b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above

Organization	Yes or No	Question 4 Comment
SPP Standards Review Group	Yes	We would suggest to the drafting team in reference to PRC-001-1.1(X) that you would evaluate adding the remaining Measures (M4, M5 and M6) to that particular section. Our concern would be that all the Measures Data pertaining to the Requirements has not been included and this has the potential of causing confusion on what evidence should be provided in an audit. Additionally, we would like the drafting team to provide more clarity on the why there's a Rationale Box for Footnotes 2 and 4 in reference to PRC-024-1(X). Footnote 2 pertains to interchangeable terms which has been revised to align with the definition of the BES. If the drafting team's objective is to focus on Footnotes 4 and 6, we would suggest changing the header of the Rationale Box to read "Rationale for Footnotes 4 and 6". Finally, we would suggest to the drafting team adding Rationale Boxes to all three standards. We feel this would provide clarity to the industry on the expectations of the Requirements in the standards as well as promoting consistency with other documentation associated with this project.
FirstEnergy	Yes	FE suggests the standard drafting team give consideration for making consistent use of Section 4 to include both a sub-section 4.1 Functional Entities and 4.2 Facilities. This would alleviate the need to bury pertinent information and clarity around what facilities are in scope within footnotes. Currently only PRC-019 includes both of these applicability sub-sections and they should be used in each standard. The sections may need to be written differently in each of the three standards but should be used in each. Furthermore, standard PRC-019-2 which currently uses sub-section 4.2 Facilities includes text that is simply repeats of what is stated in NERC BES Inclusion statement I2 which could be revised/simplified. As an example, FE believes that section 4 of PRC-019-2 could be written as follows:4 Applicability 4.1 Functional Entities 4.1.1 Generator Owner 4.1.2 Transmission Owner 4.2 Facilities 4.2.1 Generator Owner - for the purpose of this standard, the term, "applicable Facility" shall mean NERC BES Definition Inclusion I2 and I4. Where voltage regulating control for the BES generation facility is performed solely at the individual resources, those facilities are also included. 4.2.2 Transmission Owner - for the purpose of this

Organization	Yes or No	Question 4 Comment
		standard, the term, “applicable Facility” shall mean a synchronous condenser that is a qualifying BES facility under NERC BES Definition Inclusion I5.As another example, standard PRC-001-1.1 could be written as follows:4 Applicability 4.1 Functional Entities 4.1.1 Balancing Authorities 4.1.2 Transmission Operators 4.1.3 Generator Operators 4.2 Facilities 4.2.1 - This standard applies to all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher as clarified by the NERC BES definition Inclusion statements. In regard to Inclusion I4 this standard is not applicable to the individual generating units of dispersed power producing resources. One additional suggestion: Lastly, throughout the various standards there is a footnote indicating “The terms ‘dispersed generation resources’ and ‘dispersed power producing resources’ are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.” It appears this footnote is for informational purposes only during the development of standard and will be removed in the final clean version. If that is not the case, consider the need for a NERC Glossary of Term for Dispersed Generation Resource that would indicate it is synonymous with the NERC BES Definition in regard to Inclusion statement I4 for dispersed power producing resources.
Seminole Electric Cooperative, Inc.	Yes	
American Electric Power	Yes	The comment form states in part “Because two of the medium-priority standards have recently been revised or are undergoing revision in another current project...” In addition, the redline version of the standard states “Given the timing of concurrent standards development of PRC projects, PRC-024-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-024.” Both these comments infer that at least one other current project impacts PRC-024, but we cannot determine which project(s) that is. Could you provide some clarity on that?

Additional Comments:
MS Energy
Lance Bean

PRC-001-1.1(X)

- In the new bullet item of R3.1, the standards drafting team refers to individual "generating units". The BES definition Inclusion I4 includes the individual "resources". In PRC-001-1.1(X), would it make sense to replace "generating units" with "resources" to be consistent with the BES definition?

PRC-024-1(X)

- Ahead of the Introduction, there is a statement "the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard". The text box is not in the Applicability section, it is in B. Requirements, R1.
- The text box title is "Rationale for Footnotes 2 and 4". The two new footnotes are 4 and 6. I assume footnotes 1 & 2 will be removed once the Standard is approved, so perhaps the existing title is acceptable.
- The text box refers to individual "generating units". I think "generating units" should be changed to "resources".
- The text box also includes the text "it is appropriate to require that protective relay settings…are set within the no-trip zone". I think the statement should be "it is appropriate to require that protective relay settings…are **not** set within the no-trip zone"

END OF REPORT

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.
3. Initial posting of revised standard PRC-001-1.1(ii) on November 5, 2014.

Description of Current Draft

PRC-001-1.1(ii)[1] is proposed for approval to align the applicability of PRC-001-1.1 with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 – Standards Applicability for Dispersed Generation Resources standards drafting team (SDT) has coordinated with the other SDTs currently reviewing this standard and has recommended revisions to Requirement R3.1 to account for the unique characteristics of dispersed power producing resources.[2] Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.

Anticipated Actions	Anticipated Date
Final ballot	January 2015
BOT adoption	February 2015

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

[1] The standard version number included an (X) to indicate the version numbering would be updated, and NERC has since assigned the appropriate version number prior to final ballot. ,

[2] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

A. Introduction

1. **Title:** **System Protection Coordination**

2. **Number:** PRC-001-1.1(ii)

3. **Purpose:**

   To ensure system protection is coordinated among operating entities.

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Transmission Operators

   4.3. Generator Operators

5. **Effective Date:**

   See the Implementation Plan for PRC-001-1.1(ii).

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:

R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.

R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.

- Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

Rationale for the Applicability Exclusion in Requirement R3.1

Coordination of new or changes to protective systems associated with dispersed power producing resources identified through Inclusion I4 of the BES definition are typically performed on the interconnecting facilities. New or changes to protective systems associated with these facilities should be coordinated with the TOP as these protective systems typically must be closely coordinated with the transmission protective systems to ensure the overall protection systems operates as designed. While the protective systems implemented on the individual generating units of dispersed power producing resources at these dispersed power producing facilities (i.e. individual wind turbines or solar panels/inverters) may in some cases need to be coordinated with other protective systems within the same dispersed power producing facility, new or changes to these protective systems do not need to be coordinated with the transmission protective systems, as this coordination would not provide reliability benefits to the BES.

R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.

R4. Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:

R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.

R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.

R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

C. Measures

M1. Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic

logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Special Protection Systems in its area. (Requirement 6 Part 1)

M3. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Special Protection Systems. (Requirement 6 Part 2)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures 2 and 3.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Generator Operators:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

3. Levels of Non-Compliance for Transmission Operators:

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

3.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Failed to provide evidence of coordination when installing new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities as specified in R3.2.

3.4.2 Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

4. Levels of Non-Compliance for Balancing Authorities:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	August 25, 2005	Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0	Errata
1	November 1, 2006	Adopted by the NERC Board of Trustees	Revised
1.1	April 11, 2012	Errata adopted by the Standards Committee; (Capitalized "Protection System" in accordance with Implementation Plan for Project 2007-17 approval of revised definition of "Protection System")	Errata associated with Project 2007-17
1.1	September 9, 2013	Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.	
1.1(i)	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
1.1(ii))	TBD	Adopted by the NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources
2	May 9, 2012	Adopted by Board of Trustees	Deleted Requirements R2, R5, and R6.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.
~~2.~~3. Initial posting of revised standard PRC-001-1.1(ii) on November 5, 2014.

Description of Current Draft

PRC-001-1.1(~~X~~ii)[1] is proposed for approval to align the applicability of PRC-001-1.1~~a~~ with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 – Standards Applicability for Dispersed Generation Resources standards drafting team (SDT) has coordinated with the other SDTs currently reviewing this standard and has recommended revisions to Requirement R3.1 to account for the unique characteristics of dispersed power producing resources.[2] ~~Given the timing of concurrent standards development of PRC, TOP, and IRO projects, PRC-001-1.1a may be retired pursuant to an Implementation Plan of a successor version of PRC-001. If this occurs, PRC-001-1.1(X) will not go into effect.~~ Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.

Anticipated Actions	Anticipated Date
~~45-day Additional Formal Comment Period with Additional Ballot (if necessary)~~	~~December 2014~~
Final ballot	January 2015
BOT adoption	February 2015

[1] The standard version number included an (X) to indicate the version numbering would be updated, and NERC has since assigned the appropriate version number prior to final ballot.~~currently includes an (X) to indicate the version numbering will be updated. Some standards are open in current projects, and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to adoption by the NERC Board of Trustees.~~

[2] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

1. **Title:** **System Protection Coordination**

2. **Number:** PRC-001-1.1(~~X~~ii)

3. **Purpose:**

   To ensure system protection is coordinated among operating entities.

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Transmission Operators

   4.3. Generator Operators

5. **Effective Date:**

   See the Implementation Plan for ~~this standard~~PRC-001-1.1(ii).

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:

R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.

R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.

- Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

Rationale for the Applicability Exclusion in Requirement R3.1

Coordination of new or changes to protective systems associated with dispersed power producing resources identified through Inclusion I4 of the BES definition are typically performed on the interconnecting facilities. New or changes to protective systems associated with these facilities should be coordinated with the TOP as these protective systems typically must be closely coordinated with the transmission protective systems to ensure the overall protection systems operates as designed. While the protective systems implemented on the individual generating units of dispersed power producing resources at these dispersed power producing facilities (i.e. individual wind turbines or solar panels/inverters) may in some cases need to be coordinated with other protective systems within the same dispersed power producing facility, new or changes to these protective systems do not need to be coordinated with the transmission protective systems, as this coordination would not provide reliability benefits to the BES.

R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.

R4. Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:

R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.

R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.

R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

C. Measures

M1. Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic

logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Special Protection Systems in its area. (Requirement 6 Part 1)

M3. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Special Protection Systems. (Requirement 6 Part 2)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures 2 and 3.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Generator Operators:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

3. Levels of Non-Compliance for Transmission Operators:

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

3.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Failed to provide evidence of coordination when installing new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities as specified in R3.2.

3.4.2 Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

4. Levels of Non-Compliance for Balancing Authorities:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	August 25, 2005	Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0	Errata
1	November 1, 2006	Adopted by the NERC Board of Trustees	Revised
1.1	April 11, 2012	Errata adopted by the Standards Committee; (Capitalized "Protection System" in accordance with Implementation Plan for Project 2007-17 approval of revised definition of "Protection System")	Errata associated with Project 2007-17
1.1	September 9, 2013	Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.	
1.1(i)	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
~~TBD (balloted as~~ 1.1(~~X~~ii))	TBD	Adopted by the NERC Board of Trustees~~Standard revised in Project 2014-01~~	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources
2	May 9, 2012	Adopted by Board of Trustees	Deleted Requirements R2, R5, and R6.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.
3. Initial posting of revised standard PRC-001-1.1(ii) on November 5, 2014.

Description of Current Draft

PRC-001-1.1(~~X~~ii)[1] is proposed for approval to align the applicability of PRC-001-1.1~~a~~ with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 – Standards Applicability for Dispersed Generation Resources standards drafting team (SDT) has coordinated with the other SDTs currently reviewing this standard and has recommended revisions to Requirement R3.1 to account for the unique characteristics of dispersed power producing resources.[2] ~~Given the timing of concurrent standards development of PRC, TOP, and IRO projects, PRC-001-1.1a may be retired pursuant to an Implementation Plan of a successor version of PRC-001. If this occurs, PRC-001-1.1(X) will not go into effect.~~ Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.

Anticipated Actions	Anticipated Date
Final ballot	January 2015
BOT adoption	February 2015

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

[1] The standard version number included an (X) to indicate the version numbering would be updated, and NERC has since assigned the appropriate version number prior to final ballot.~~currently includes an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to adoption by the NERC Board of Trustees.~~

[2] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

A. Introduction

1. **Title:** **System Protection Coordination**

2. **Number:** PRC-001-1.1(Xii)

3. **Purpose:**

   To ensure system protection is coordinated among operating entities.

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Transmission Operators

   4.3. Generator Operators

5. **Effective Date:** ~~January 1, 2007~~

   See the Implementation Plan for ~~this standard~~PRC-001-1.1(ii).

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:

R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.

R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.

- Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

Rationale for the Applicability Exclusion in Requirement R3.1

Coordination of new or changes to protective systems associated with dispersed power producing resources identified through Inclusion I4 of the BES definition are typically performed on the interconnecting facilities. New or changes to protective systems associated with these facilities should be coordinated with the TOP as these protective systems typically must be closely coordinated with the transmission protective systems to ensure the overall protection systems operates as designed. While the protective systems implemented on the individual generating units of dispersed power producing resources at these dispersed power producing facilities (i.e. individual wind turbines or solar panels/inverters) may in some cases need to be coordinated with other protective systems within the same dispersed power producing facility, new or changes to these protective systems do not need to be coordinated with the transmission protective systems, as this coordination would not provide reliability benefits to the BES.

R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.

R4. Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:

R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.

R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.

R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

C. Measures

M1. Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic

logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Special Protection Systems in its area. (Requirement 6 Part 1)

M3. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Special Protection Systems. (Requirement 6 Part 2)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures 2 and 3.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Generator Operators:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

3. Levels of Non-Compliance for Transmission Operators:

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

3.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Failed to provide evidence of coordination when installing new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities as specified in R3.2.

3.4.2 Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

4. Levels of Non-Compliance for Balancing Authorities:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	August 25, 2005	Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0	Errata
1	November 1, 2006	Adopted by the NERC Board of Trustees	Revised
1.1	April 11, 2012	Errata adopted by the Standards Committee; (Capitalized "Protection System" in accordance with Implementation Plan for Project 2007-17 approval of revised definition of "Protection System")	Errata associated with Project 2007-17
1.1	September 9, 2013	Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.	
1.1(i)	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
1.1(ii))	TBD	Adopted by the NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources
2	May 9, 2012	Adopted by Board of Trustees	Deleted Requirements R2, R5, and R6.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.
3. Initial posting of revised standard PRC-019-2 on November 5, 2014.

Description of Current Draft

PRC-019-2 is proposed for approval to align the applicability section of PRC-019-1 with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 – Standards Applicability for Dispersed Generation Resources standards drafting team has recommended revisions to the Facilities section to clarify that facilities that solely regulate voltage at the individual generating unit are subject to the requirements. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.[1]

Anticipated Actions	Anticipated Date
Final ballot	January 2015
BOT adoption	February 2015

[1] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

1. **Title:** Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

2. **Number:** PRC-019-2

3. **Purpose:** To verify coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings.

4. **Applicability:**

   4.1. Functional Entities

   4.1.1 Generator Owner

   4.1.2 Transmission Owner that owns synchronous condenser(s)

   4.2. Facilities

   For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following:

   4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

   4.2.2 Individual synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

   4.2.3 Generating plant/ Facility consisting of one or more units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

   4.2.3.1 This includes individual generating units of the dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition where voltage regulating control for the facility is performed solely at the individual generating unit of the dispersed power producing resources.

Rationale for Facilities section 4.2.3.1

For those dispersed power producing facilities that only perform voltage regulating control at the individual generating unit level, the SDT believes that coordination should take place at the individual generating unit level of the dispersed power producing resource. These facilities need to consider the Protection Systems at the individual units and their compatibility with the reactive and voltage limitations of the units. Where voltage regulating control is done at an aggregate level, applicability is already included under Facilities section 4.2.3.

4.2.4 Any generator, regardless of size, that is a blackstart unit material to and designated as part of a Transmission Operator's restoration plan.

5. Effective Date:

See the Implementation Plan for PRC-019-2.

B. Requirements

R1. At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls, (including in-service[2] limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Assuming the normal automatic voltage regulator control loop and steady-state system operating conditions, verify the following coordination items for each applicable Facility:

1.1.1. The in-service limiters are set to operate before the Protection System of the applicable Facility in order to avoid disconnecting the generator unnecessarily.

1.1.2. The applicable in-service Protection System devices are set to operate to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits.

R2. Within 90 calendar days following the identification or implementation of systems, equipment or setting changes that will affect the coordination described in Requirement R1, each Generator Owner and Transmission Owner with applicable Facilities shall perform the coordination as described in Requirement R1. These possible systems, equipment or settings changes include, but are not limited to the following *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

- Voltage regulating settings or equipment changes;
- Protection System settings or component changes;
- Generating or synchronous condenser equipment capability changes; or
- Generator or synchronous condenser step-up transformer changes.

C. Measures

M1. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence (such as examples provided in PRC-019 Section G) that it coordinated the

[2] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

voltage regulating system controls, including in-service[3] limiters and protection functions, with the applicable equipment capabilities and settings of the applicable Protection System devices and functions as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed.

M2. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence of the coordination required by the events listed in Requirement R2. This evidence should include dated documentation that demonstrates the specified intervals in Requirement R2 have been met.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention

The following evidence retention periods identify a period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention specified below is shorter than the time since the last compliance audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Owner shall retain evidence of compliance with Requirements R1 and R2, Measures M1 and M2 for six years.

If a Generator Owner or Transmission Owner is found non-compliant, the entity shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last periodic audit report and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

[3] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years but less than or equal to 5 calendar years plus 4 months after the previous coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years plus 4 months but less than or equal to 5 calendar years plus 8 months after the previous coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years plus 8 months but less than or equal to 5 calendar years plus 12 months after the previous coordination.	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 5 calendar years plus 12 months after the previous coordination.
R2	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 90 calendar days but less than or equal to 100 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 100 calendar days but less than or equal to 110 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 110 calendar days but less than or equal to 120 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 120 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.

E. Regional Variances

None.

F. Associated Documents

"Underexcited Operation of Turbo Generators", AIEE Proceedings T Section 881, Volume 67, 1948, Appendix 1, C. G. Adams and J. B. McClure.

,"Protective Relaying For Power Generation Systems", Boca Raton, FL, Taylor & Francis, 2006, Reimert, Donald

"Coordination of Generator Protection with Generator Excitation Control and Generator Capability", a report of Working Group J5 of the IEEE PSRC Rotating Machinery Subcommittee

"IEEE C37.102-2006 IEEE Guide for AC Generator Protection"

"IEEE C50.13-2005 IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above"

Version History

Version	Date	Action	Change Tracking
1	February 7, 2013	Adopted by NERC Board of Trustees	New
2	TBD	Adopted by NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources

G. Reference

Examples of Coordination

The evidence of coordination associated with Requirement R1 may be in the form of:

- P-Q Diagram (Example in Attachment 1), or
- R-X Diagram (Example in Attachment 2), or
- Inverse Time Diagram (Example in Attachment 3) or,
- Equivalent tables or other evidence

This evidence should include the equipment capabilities and the operating region for the limiters and protection functions

Equipment limits, types of limiters and protection functions which could be coordinated include (but are not limited to):

- Field over-excitation limiter and associated protection functions.
- Inverter over current limit and associated protection functions.
- Field under-excitation limiter and associated protection functions.
- Generator or synchronous condenser reactive capabilities.
- Volts per hertz limiter and associated protection functions.
- Stator over-voltage protection system settings.
- Generator and transformer volts per hertz capability.
- Time vs. field current or time vs. stator current.

NOTE: This listing is for reference only. This standard does not require the installation or activation of any of the above limiter or protection functions.

For this example, the Steady State Stability Limit (SSSL) is the limit to synchronous stability in the under-excited region with fixed field current.

On a P-Q diagram using X_d as the direct axis saturated synchronous reactance of the generator, X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer and V_g as the generator terminal voltage (all values in per-unit), the SSSL can be calculated as an arc with the center on the Q axis with the magnitude of the center and radius described by the following equations

$C = V^2_g/2*(1/X_s-1/X_d)$

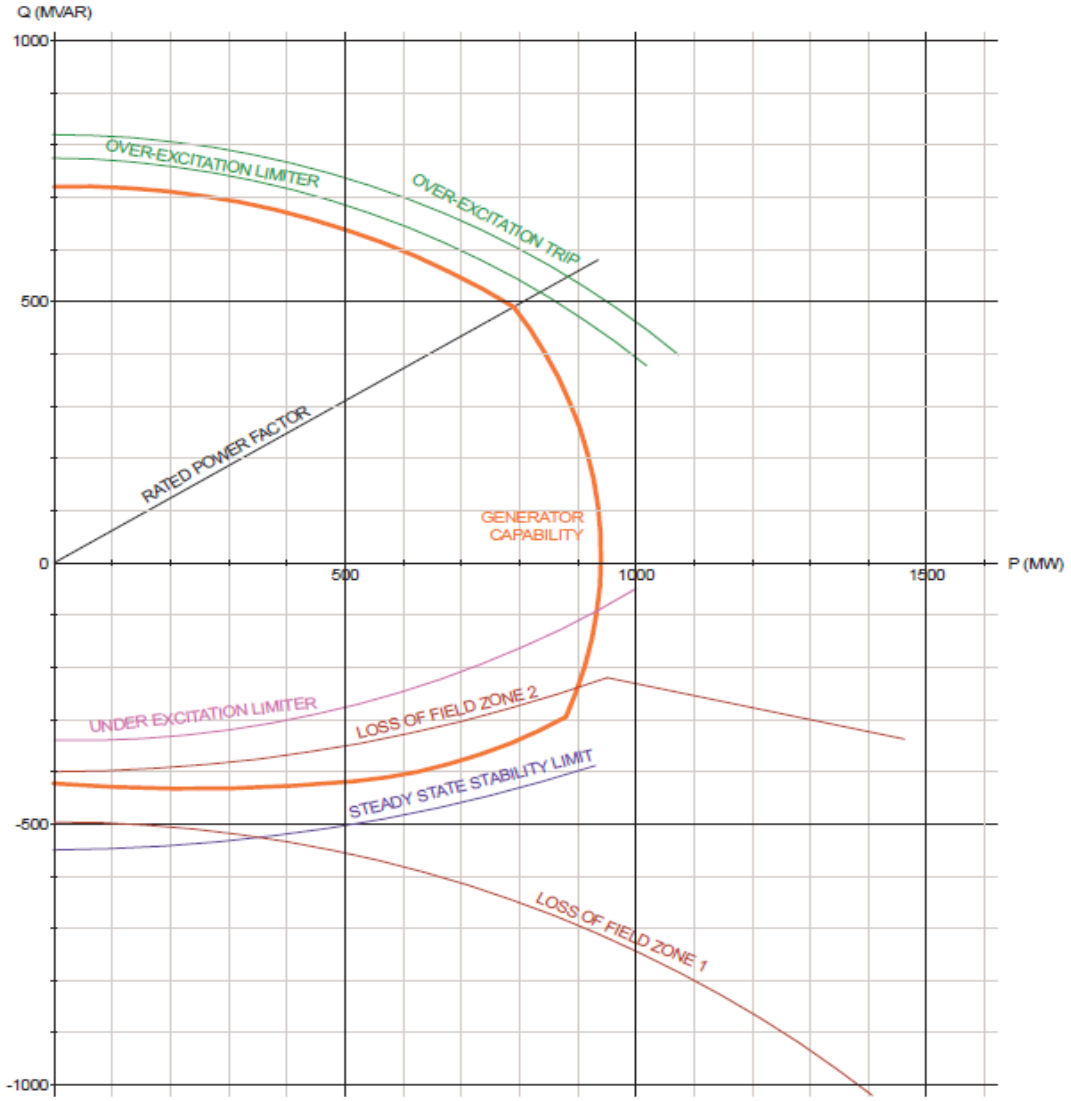
$R = V^2_g/2*(1/X_s+1/X_d)$

On an R-X diagram using X_d as the direct axis saturated synchronous reactance of the generator, and X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer the SSSL is an arc with the center on the X axis with the center and radius described by the following equations:

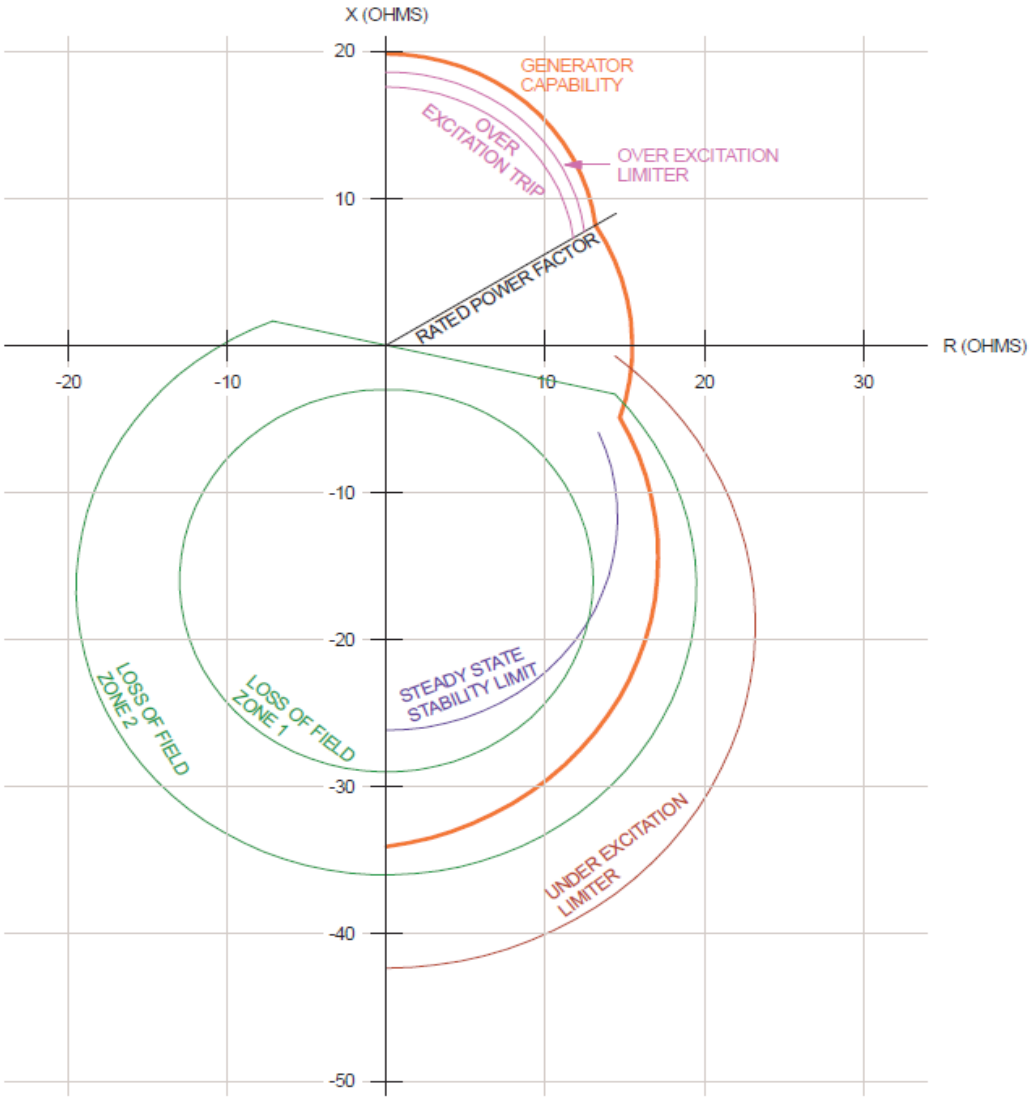
$C = (X_d-X_s)/2$

$R = (X_d+X_s)/2$

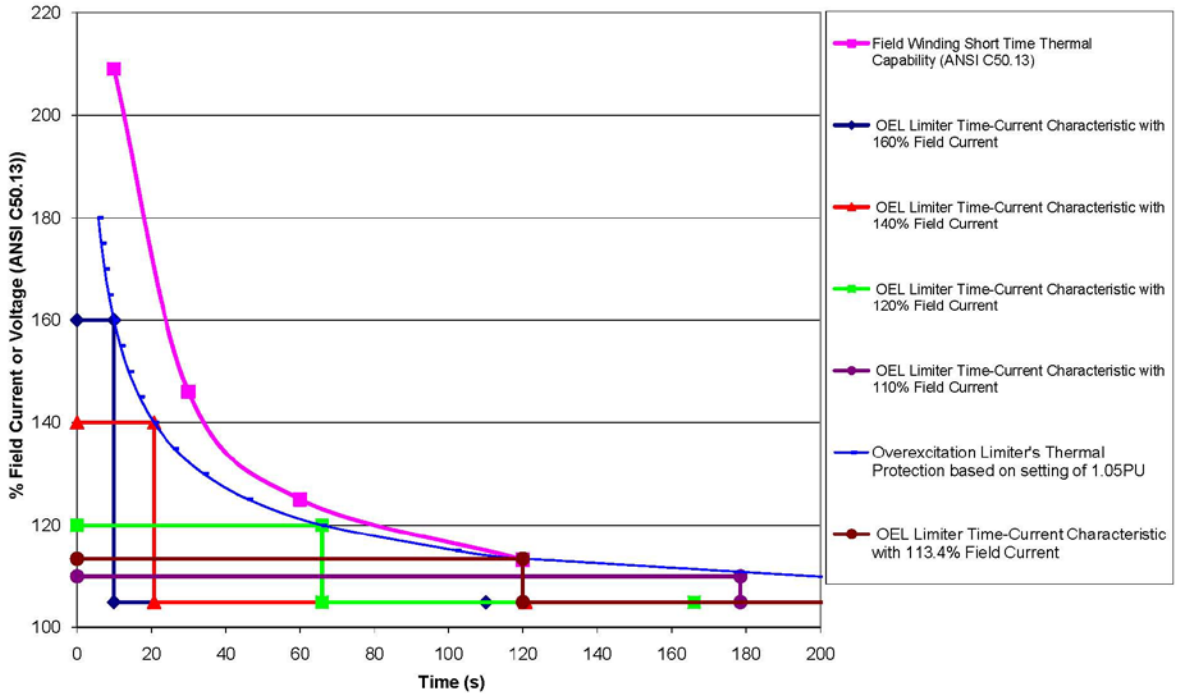
Section G Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency



Section G Attachment 2 – Example of Capabilities, Limiters, and Protection on an R-X Diagram at nominal voltage and frequency



Section G Attachment 3 - Example of Capabilities, Limiters, and Protection on an Inverse Time Characteristic Plot



Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.
~~2.~~3. Initial posting of revised standard PRC-019-2 on November 5, 2014.

Description of Current Draft

PRC-019-2 is proposed for approval to align the applicability section of PRC-019-1 with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 – Standards Applicability for Dispersed Generation Resources standards drafting team has recommended revisions to the Facilities section to clarify that facilities that solely regulate voltage at the individual generating unit are subject to the requirements. ~~Given the timing of concurrent standards development of PRC projects, PRC-019-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-019. If this occurs, PRC-019-2 will not go into effect.~~ Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.[1]

Anticipated Actions	Anticipated Date
~~45-day Additional Formal Comment Period with Additional Ballot (if necessary)~~	~~December 2014~~
Final ballot	January 2015
BOT adoption	February 2015

[1] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

1. **Title:** Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

2. **Number:** PRC-019-2

3. **Purpose:** To verify coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings.

4. **Applicability:**

   4.1. Functional Entities

   4.1.1 Generator Owner

   4.1.2 Transmission Owner that owns synchronous condenser(s)

   4.2. Facilities

   For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following:

   4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

   4.2.2 Individual synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

   4.2.3 Generating plant/ Facility consisting of one or more units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

   4.2.3.1 This includes individual generating units of the dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition where voltage regulating control for the facility is performed solely at the individual generating unit of the dispersed power producing resources.

Rationale for Facilities section 4.2.3.1

For those dispersed power producing facilities that only perform voltage regulating control at the individual generating unit level, the SDT believes that coordination should take place at the individual generating unit level of the dispersed power producing resource ~~level~~. These facilities need to consider the Protection Systems at the individual units and their compatibility with the reactive and voltage limitations of the units. Where voltage regulating control is done at an aggregate level, applicability is already included under Facilities section 4.2.3.

4.2.4 Any generator, regardless of size, that is a blackstart unit material to and designated as part of a Transmission Operator's restoration plan.

5. Effective Date:

See the Implementation Plan for PRC-019-2~~this standard~~.

B. Requirements

R1. At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls, (including in-service[2] limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Assuming the normal automatic voltage regulator control loop and steady-state system operating conditions, verify the following coordination items for each applicable Facility:

1.1.1. The in-service limiters are set to operate before the Protection System of the applicable Facility in order to avoid disconnecting the generator unnecessarily.

1.1.2. The applicable in-service Protection System devices are set to operate to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits.

R2. Within 90 calendar days following the identification or implementation of systems, equipment or setting changes that will affect the coordination described in Requirement R1, each Generator Owner and Transmission Owner with applicable Facilities shall perform the coordination as described in Requirement R1. These possible systems, equipment or settings changes include, but are not limited to the following *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

- Voltage regulating settings or equipment changes;
- Protection System settings or component changes;
- Generating or synchronous condenser equipment capability changes; or
- Generator or synchronous condenser step-up transformer changes.

C. Measures

M1. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence (such as examples provided in PRC-019 Section G) that it coordinated the

[2] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

voltage regulating system controls, including in-service[3] limiters and protection functions, with the applicable equipment capabilities and settings of the applicable Protection System devices and functions as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed.

M2. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence of the coordination required by the events listed in Requirement R2. This evidence should include dated documentation that demonstrates the specified intervals in Requirement R2 have been met.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention

The following evidence retention periods identify a period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention specified below is shorter than the time since the last compliance audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Owner shall retain evidence of compliance with Requirements R1 and R2, Measures M1 and M2 for six years.

If a Generator Owner or Transmission Owner is found non-compliant, the entity shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last periodic audit report and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

[3] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years but less than or equal to 5 calendar years plus 4 months after the previous coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years plus 4 months but less than or equal to 5 calendar years plus 8 months after the previous coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years plus 8 months but less than or equal to 5 calendar years plus 12 months after the previous coordination.	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 5 calendar years plus 12 months after the previous coordination.
R2	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 90 calendar days but less than or equal to 100 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 100 calendar days but less than or equal to 110 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 110 calendar days but less than or equal to 120 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 120 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.

E. Regional Variances

None.

F. Associated Documents

"Underexcited Operation of Turbo Generators", AIEE Proceedings T Section 881, Volume 67, 1948, Appendix 1, C. G. Adams and J. B. McClure.

,"Protective Relaying For Power Generation Systems", Boca Raton, FL, Taylor & Francis, 2006, Reimert, Donald

"Coordination of Generator Protection with Generator Excitation Control and Generator Capability", a report of Working Group J5 of the IEEE PSRC Rotating Machinery Subcommittee

"IEEE C37.102-2006 IEEE Guide for AC Generator Protection"

"IEEE C50.13-2005 IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above"

Version History

Version	Date	Action	Change Tracking
1	February 7, 2013	Adopted by NERC Board of Trustees	New
~~1~~	~~March 20, 2014~~	~~FERC Order issued approving PRC-019-1. (Order becomes effective on 7/1/16.)~~	
2	TBD	Adopted by NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources

G. Reference

Examples of Coordination

The evidence of coordination associated with Requirement R1 may be in the form of:

- P-Q Diagram (Example in Attachment 1), or
- R-X Diagram (Example in Attachment 2), or
- Inverse Time Diagram (Example in Attachment 3) or,
- Equivalent tables or other evidence

This evidence should include the equipment capabilities and the operating region for the limiters and protection functions

Equipment limits, types of limiters and protection functions which could be coordinated include (but are not limited to):

- Field over-excitation limiter and associated protection functions.
- Inverter over current limit and associated protection functions.
- Field under-excitation limiter and associated protection functions.
- Generator or synchronous condenser reactive capabilities.
- Volts per hertz limiter and associated protection functions.
- Stator over-voltage protection system settings.
- Generator and transformer volts per hertz capability.
- Time vs. field current or time vs. stator current.

NOTE: This listing is for reference only. This standard does not require the installation or activation of any of the above limiter or protection functions.

For this example, the Steady State Stability Limit (SSSL) is the limit to synchronous stability in the under-excited region with fixed field current.

On a P-Q diagram using X_d as the direct axis saturated synchronous reactance of the generator, X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer and V_g as the generator terminal voltage (all values in per-unit), the SSSL can be calculated as an arc with the center on the Q axis with the magnitude of the center and radius described by the following equations

$$C = V^2_g/2*(1/X_s-1/X_d)$$

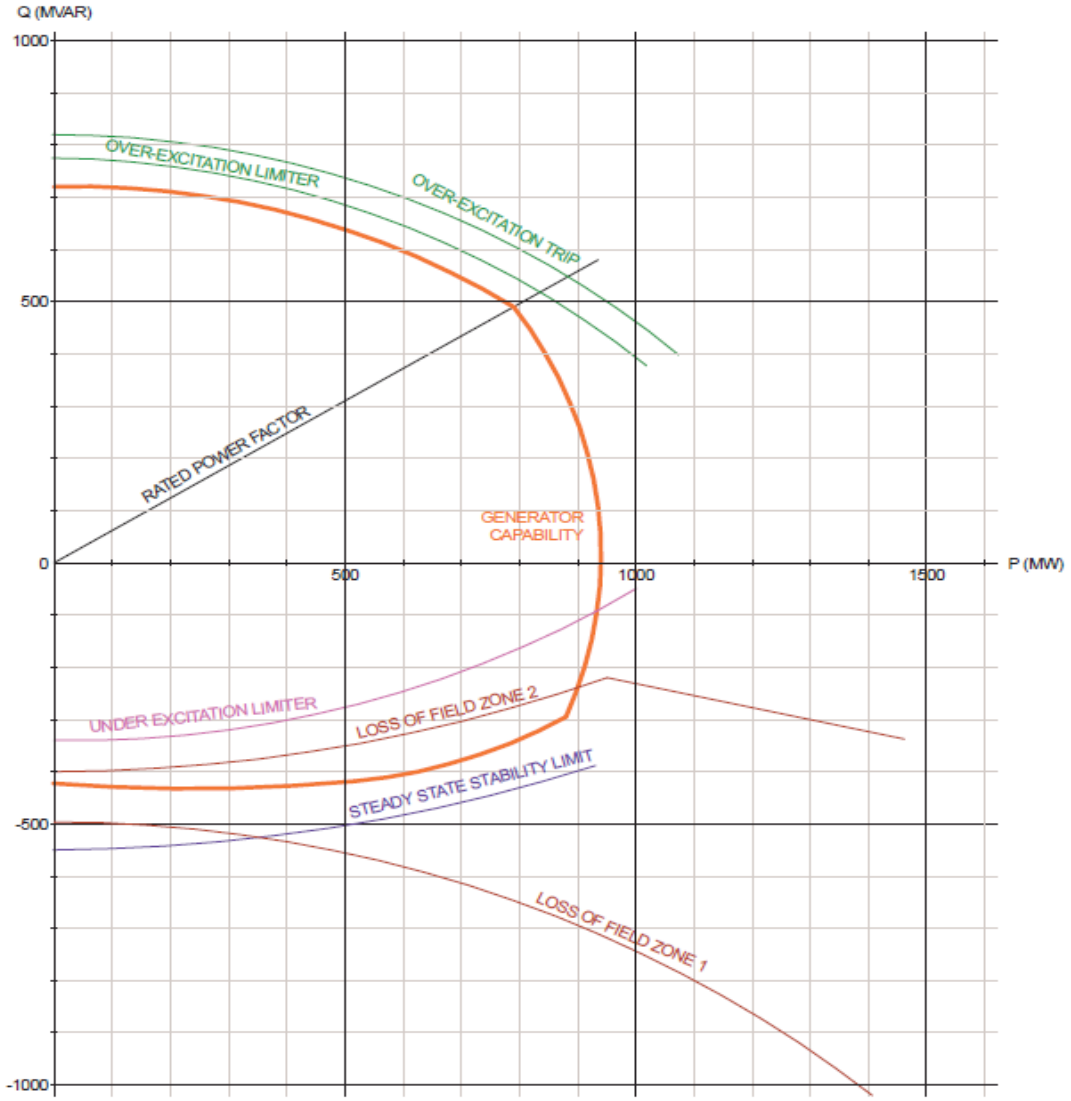
$$R = V^2_g/2*(1/X_s+1/X_d)$$

On an R-X diagram using X_d as the direct axis saturated synchronous reactance of the generator, and X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer the SSSL is an arc with the center on the X axis with the center and radius described by the following equations:

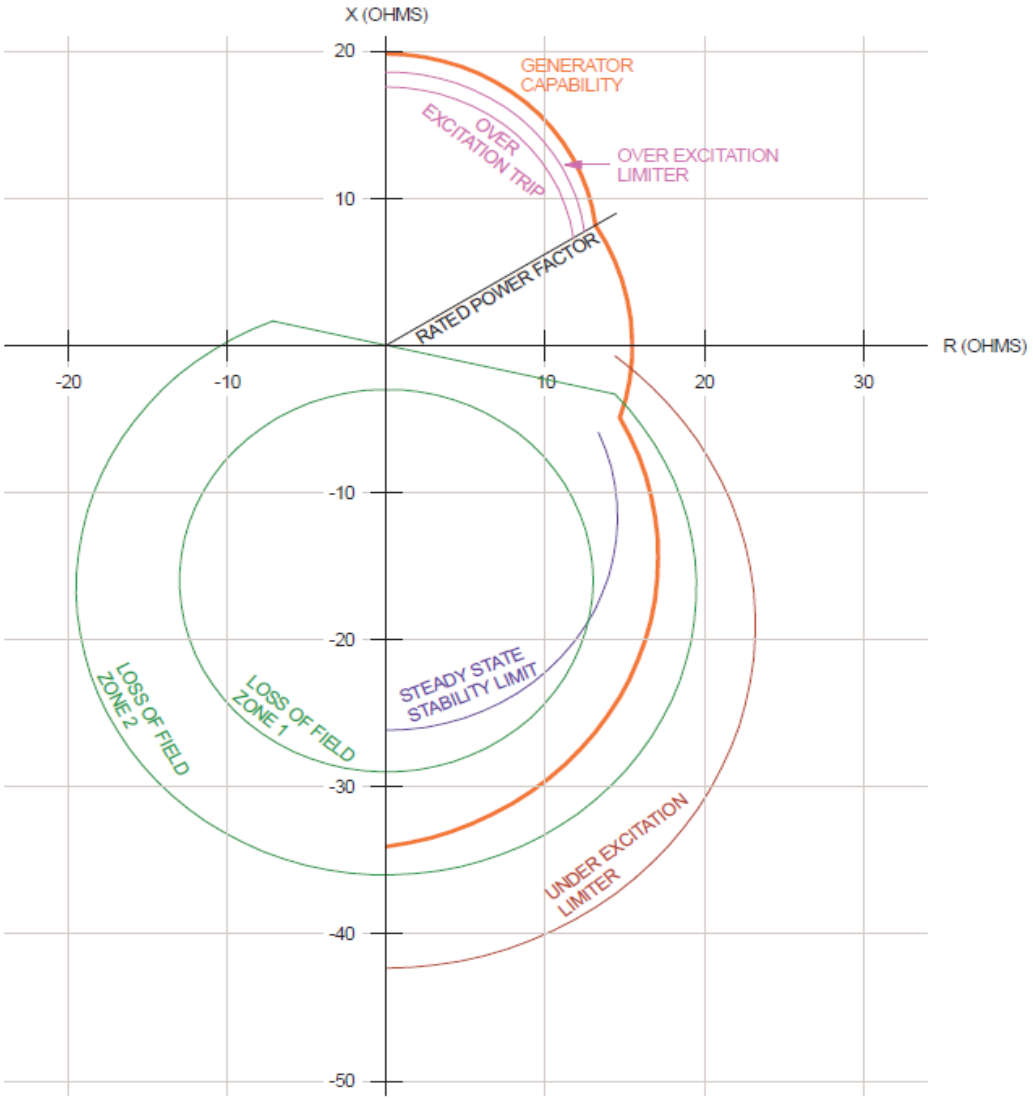
$$C = (X_d-X_s)/2$$

$$R = (X_d+X_s)/2$$

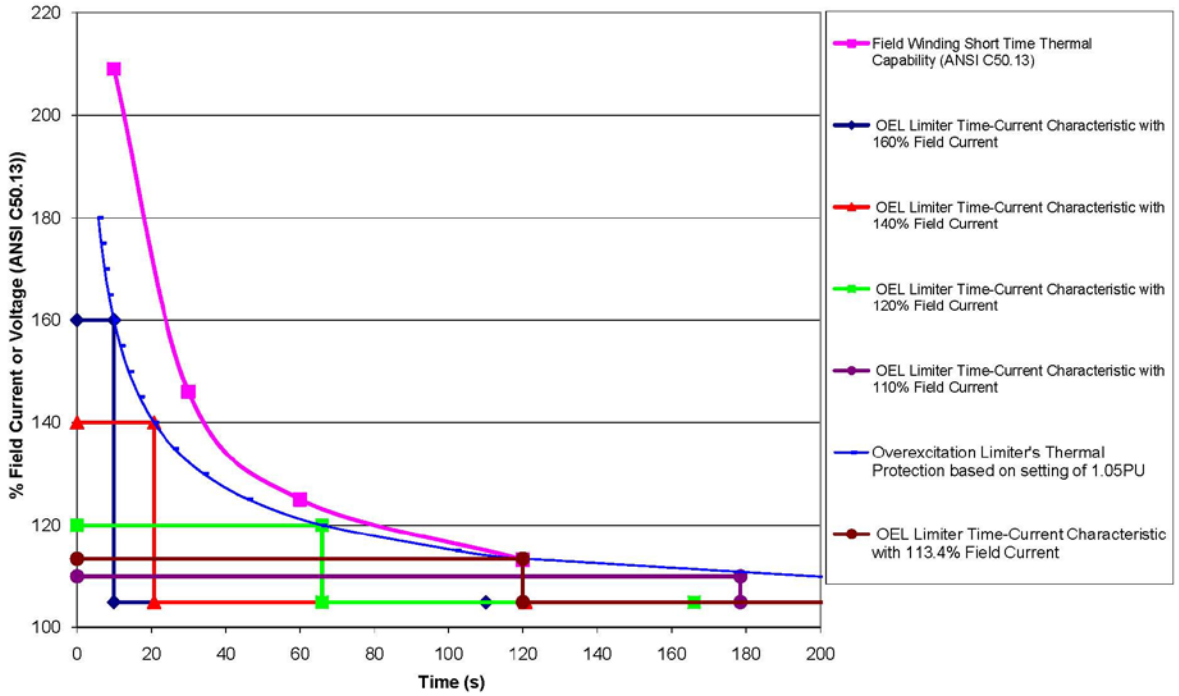
Section G Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency



Section G Attachment 2 – Example of Capabilities, Limiters, and Protection on an R-X Diagram at nominal voltage and frequency



Section G Attachment 3 - Example of Capabilities, Limiters, and Protection on an Inverse Time Characteristic Plot



Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.
3. Initial posting of revised standard PRC-019-2 on November 5, 2014.

Description of Current Draft

PRC-019-2 is proposed for approval to align the applicability section of PRC-019-1 with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 – Standards Applicability for Dispersed Generation Resources standards drafting team has recommended revisions to the Facilities section to clarify that facilities that solely regulate voltage at the individual generating unit are subject to the requirements. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.[1]

Anticipated Actions	Anticipated Date
Final ballot	January 2015
BOT adoption	February 2015

[1] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Application Guidelines Section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

1. **Title:** Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

2. **Number:** PRC-019-21

3. **Purpose:** To verify coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings.

4. **Applicability:**

   4.1. Functional Entities

   4.1.1 Generator Owner

   4.1.2 Transmission Owner that owns synchronous condenser(s)

   4.2. Facilities

   For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following:

   4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

   4.2.2 Individual synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

   4.2.3 Generating plant/ Facility consisting of one or more units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

   4.2.3.1 This includes individual generating units of the dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition where voltage regulating control for the facility is performed solely at the individual generating unit of the dispersed power producing resources.

Rationale for Facilities section 4.2.3.1

For those dispersed power producing facilities that only perform voltage regulating control at the individual generating unit level, the SDT believes that coordination should take place at the individual generating unit level of the dispersed power producing resource ~~level~~. These facilities need to consider the Protection Systems at the individual units and their compatibility with the reactive and voltage limitations of the units. Where voltage regulating control

is done at an aggregate level, applicability is already included under Facilities section 4.2.3.

4.2.4 Any generator, regardless of size, that is a blackstart unit material to and designated as part of a Transmission Operator's restoration plan.

5. Effective Date:

See the Implementation Plan for PRC-019-2~~this standard~~.

~~**5.1.** In those jurisdictions where regulatory approval is required:~~

~~**5.1.1** By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.~~

~~**5.1.2** By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.~~

~~**5.1.3** By the first day of the first calendar quarter, four calendar years following applicable regulatory, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, approval each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.~~

~~**5.1.4** By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.~~

~~**5.2.** In those jurisdictions where regulatory approval is not required:~~

~~**5.2.1** By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.~~

~~**5.2.2** By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.~~

~~5.2.3 By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.~~

~~5.2.4 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.~~

B. Requirements

R1. At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls, (including in-service[2] limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Assuming the normal automatic voltage regulator control loop and steady-state system operating conditions, verify the following coordination items for each applicable Facility:

1.1.1. The in-service limiters are set to operate before the Protection System of the applicable Facility in order to avoid disconnecting the generator unnecessarily.

1.1.2. The applicable in-service Protection System devices are set to operate to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits.

R2. Within 90 calendar days following the identification or implementation of systems, equipment or setting changes that will affect the coordination described in Requirement R1, each Generator Owner and Transmission Owner with applicable Facilities shall perform the coordination as described in Requirement R1. These possible systems, equipment or settings changes include, but are not limited to the following *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

- Voltage regulating settings or equipment changes;
- Protection System settings or component changes;
- Generating or synchronous condenser equipment capability changes; or
- Generator or synchronous condenser step-up transformer changes.

[2] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

C. Measures

M1. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence (such as examples provided in PRC-019 Section G) that it coordinated the voltage regulating system controls, including in-service[3] limiters and protection functions, with the applicable equipment capabilities and settings of the applicable Protection System devices and functions as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed.

M2. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence of the coordination required by the events listed in Requirement R2. This evidence should include dated documentation that demonstrates the specified intervals in Requirement R2 have been met.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention

The following evidence retention periods identify a period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention specified below is shorter than the time since the last compliance audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Owner shall retain evidence of compliance with Requirements R1 and R2, Measures M1 and M2 for six years.

If a Generator Owner or Transmission Owner is found non-compliant, the entity shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer.

[3] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

The Compliance Enforcement Authority shall keep the last periodic audit report and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years but less than or equal to 5 calendar years plus 4 months after the previous coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years plus 4 months but less than or equal to 5 calendar years plus 8 months after the previous coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years plus 8 months but less than or equal to 5 calendar years plus 12 months after the previous coordination.	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 5 calendar years plus 12 months after the previous coordination.
R2	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 90 calendar days but less than or equal to 100 calendar days following the	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 100 calendar days but less than or equal to 110 calendar days following the	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 110 calendar days but less than or equal to 120 calendar days following the	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 120 calendar days following the identification or implementation of a change in equipment

	identification or implementation of a change in equipment or settings that affected the coordination.	identification or implementation of a change in equipment or settings that affected the coordination.	identification or implementation of a change in equipment or settings that affected the coordination.	or settings that affected the coordination.

E. Regional Variances

None.

F. Associated Documents

"Underexcited Operation of Turbo Generators", AIEE Proceedings T Section 881, Volume 67, 1948, Appendix 1, C. G. Adams and J. B. McClure.

,"Protective Relaying For Power Generation Systems", Boca Raton, FL, Taylor & Francis, 2006, Reimert, Donald

"Coordination of Generator Protection with Generator Excitation Control and Generator Capability", a report of Working Group J5 of the IEEE PSRC Rotating Machinery Subcommittee

"IEEE C37.102-2006 IEEE Guide for AC Generator Protection"

"IEEE C50.13-2005 IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above"

Version History

Version	Date	Action	Change Tracking
1	February 7, 2013	Adopted by NERC Board of Trustees	New
1	March 20, 2014	FERC Order issued approving PRC-019-1. (Order becomes effective on 7/1/16.)	
2	TBD	Adopted by NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources

G. Reference

Examples of Coordination

The evidence of coordination associated with Requirement R1 may be in the form of:

- P-Q Diagram (Example in Attachment 1), or
- R-X Diagram (Example in Attachment 2), or
- Inverse Time Diagram (Example in Attachment 3) or,
- Equivalent tables or other evidence

This evidence should include the equipment capabilities and the operating region for the limiters and protection functions

Equipment limits, types of limiters and protection functions which could be coordinated include (but are not limited to):

- Field over-excitation limiter and associated protection functions.
- Inverter over current limit and associated protection functions.
- Field under-excitation limiter and associated protection functions.
- Generator or synchronous condenser reactive capabilities.
- Volts per hertz limiter and associated protection functions.
- Stator over-voltage protection system settings.
- Generator and transformer volts per hertz capability.
- Time vs. field current or time vs. stator current.

NOTE: This listing is for reference only. This standard does not require the installation or activation of any of the above limiter or protection functions.

For this example, the Steady State Stability Limit (SSSL) is the limit to synchronous stability in the under-excited region with fixed field current.

On a P-Q diagram using X_d as the direct axis saturated synchronous reactance of the generator, X_s as the equivalent reactance between the generator terminals and the

"infinite bus" including the reactance of the generator step-up transformer and V_g as the generator terminal voltage (all values in per-unit), the SSSL can be calculated as an arc with the center on the Q axis with the magnitude of the center and radius described by the following equations

$$C = V^2_g/2*(1/X_s-1/X_d)$$

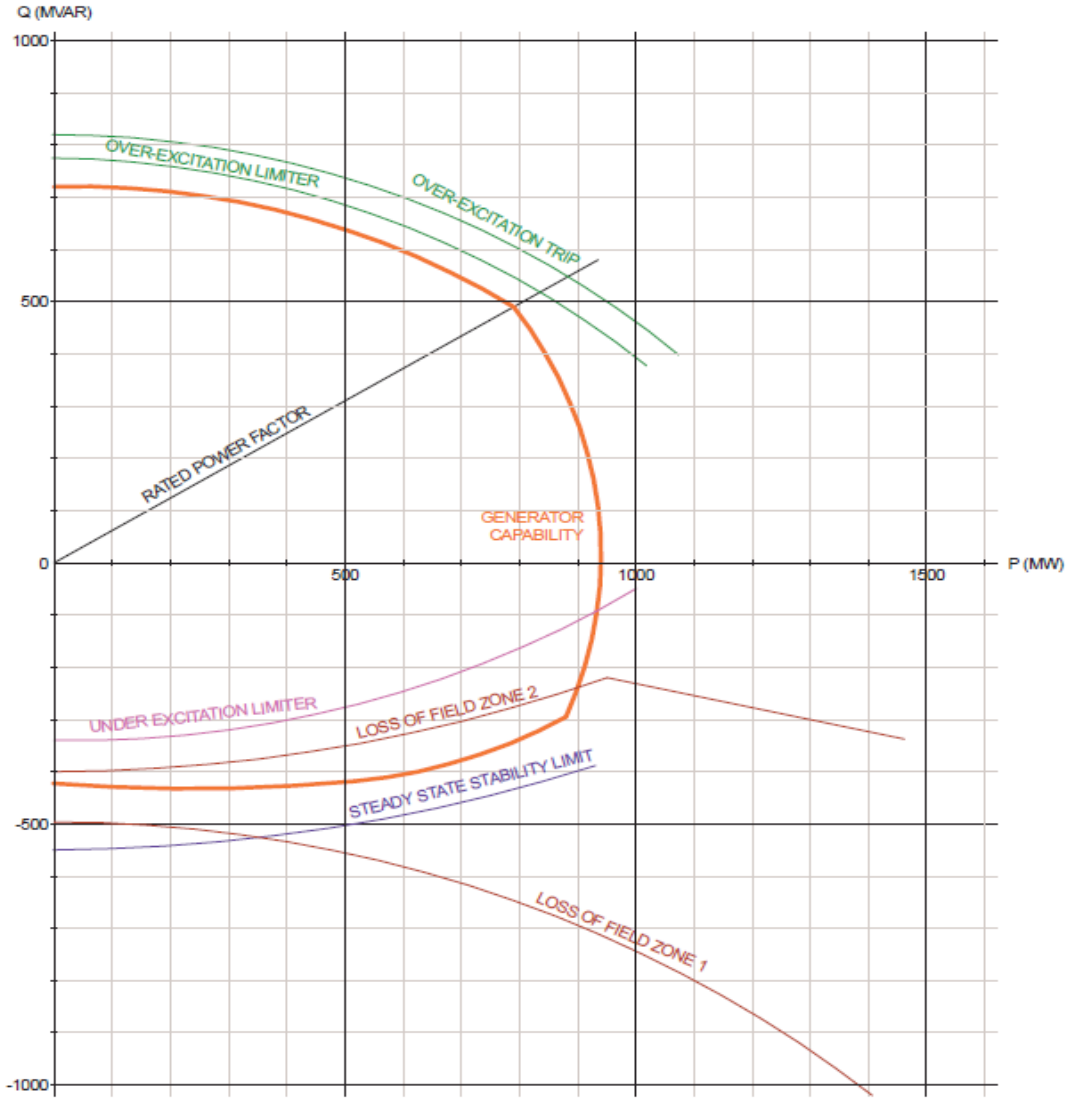
$$R = V^2_g/2*(1/X_s+1/X_d)$$

On an R-X diagram using X_d as the direct axis saturated synchronous reactance of the generator, and X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer the SSSL is an arc with the center on the X axis with the center and radius described by the following equations:

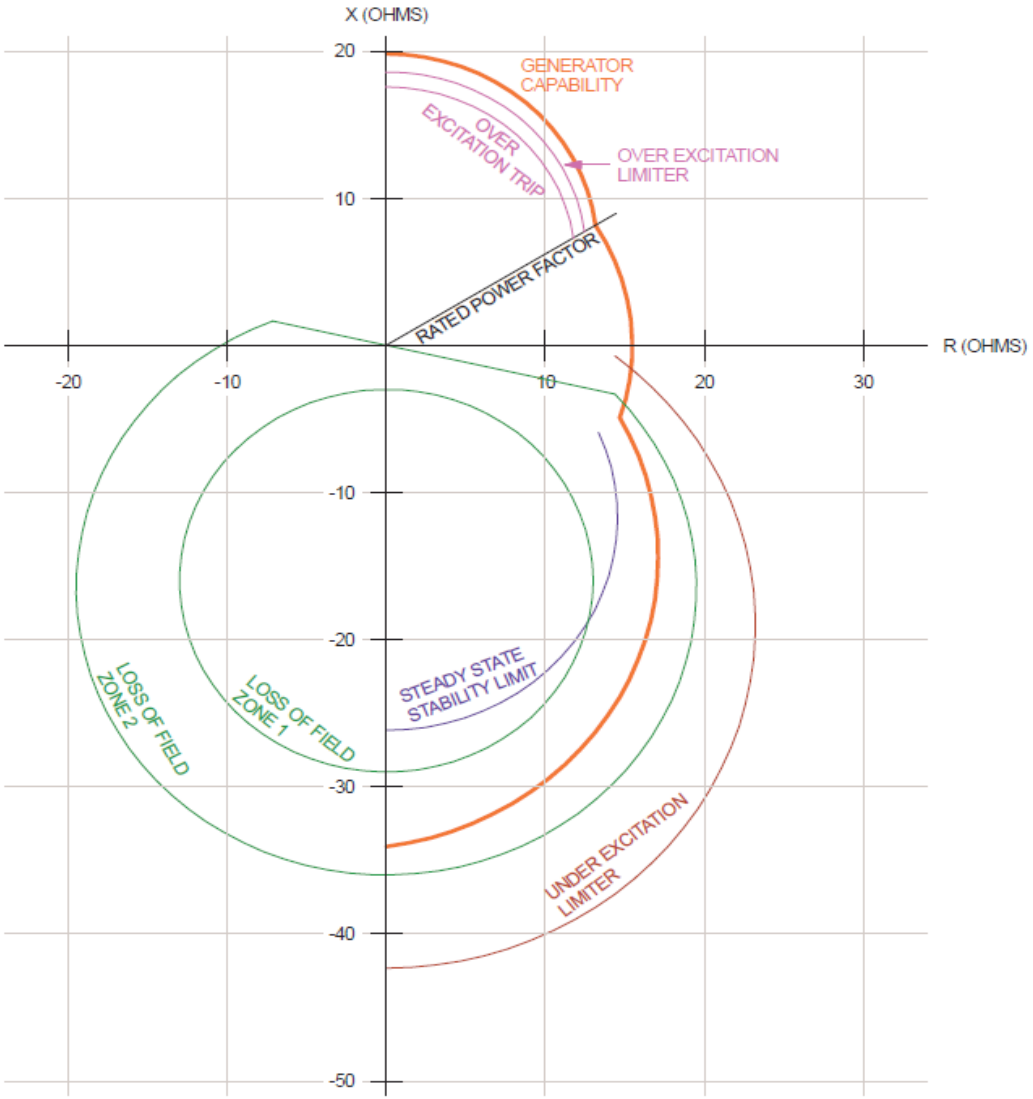
$$C = (X_d-X_s)/2$$

$$R = (X_d+X_s)/2$$

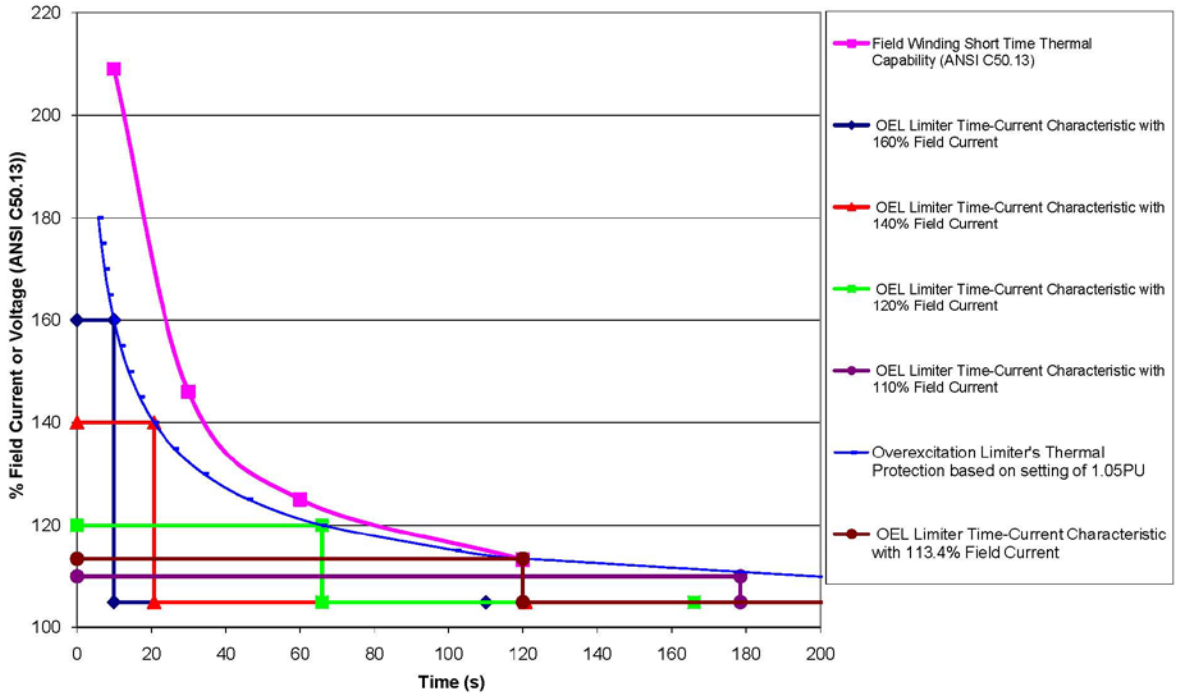
Section G Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency



Section G Attachment 2 – Example of Capabilities, Limiters, and Protection on an R-X Diagram at nominal voltage and frequency



Section G Attachment 3 - Example of Capabilities, Limiters, and Protection on an Inverse Time Characteristic Plot



Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.
3. Initial posting of revised standard PRC-024-2 on November 5, 2014.

Description of Current Draft

PRC-024-2[1] is proposed for approval to align the applicability section of PRC-024-1 with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 –Standards Applicability for Dispersed Generation Resources standards drafting team recommended changes to the requirements addressing the scope of applicability and also recommended changes to the Reliability Standard Audit Worksheet to address documentation options. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.[2]

Anticipated Actions	Anticipated Date
Final ballot	January 2015
BOT adoption	February 2015

[1] The standard version number included an (X) to indicate the version numbering would be updated, and NERC has since assigned the appropriate version number prior to final ballot.

[2] The terms “dispersed generation resources” and “dispersed power producing resources” are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

1. **Title:** **Generator Frequency and Voltage Protective Relay Settings**
2. **Number:** PRC-024-2
3. **Purpose:** Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.
4. **Applicability:**

   4.1. Generator Owner

5. **Effective Date:**

   See the Implementation Plan for PRC-024-2.

B. Requirements

R1. Each Generator Owner that has generator frequency protective relaying[3] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the "no trip zone" of PRC-024 Attachment 1, subject to the following exceptions:[4] *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

[3] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

[4] For frequency protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to frequency protective relays applied on the individual generating unit of the dispersed power producing resources, as well as frequency protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.

Rationale for Footnotes 4 and 6

The SDT has determined it is appropriate to require that protective relay settings applied on both the individual generating units and aggregating equipment (including any non-Bulk Electric System collection system equipment) are set respecting the "no-trip zone" referenced in the requirements to maintain reliability of the BES. If any of the protective relay settings applied on these elements of the facility were to be excluded from this standard, the potential would exist for portions of or the entire generating capacity of the dispersed power producing facility to be lost during a voltage or frequency excursion.

R2. Each Generator Owner that has generator voltage protective relaying[3] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection[5]) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2.[6] If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner's study. Requirement R2 is subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

[5] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

[6] For voltage protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to voltage protective relays applied on the individual generating unit of the dispersed power producing resources, as well as voltage protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.

R3. Each Generator Owner shall document each known regulatory or equipment limitation[7] that prevents an applicable generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:

- Identification of a regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.
- Replacement of the equipment causing the limitation with equipment that removes the limitation.
- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.

R4. Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets or other documentation.

M2. Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, dynamic simulation studies or other documentation.

M3. Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.

[7] Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.

M4. Each Generator Owner shall have evidence that it communicated applicable generator protective relay trip settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases, the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner shall retain evidence of compliance with Requirement R1 through R4; for 3 years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, the Generator Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generating unit, failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit, failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	OR The Generator Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.
R4	The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner failed to provide its generator protection trip settings within 150 calendar days of any change to those trip settings. OR The Generator Owner failed to provide trip settings within 150 calendar days of a written request.

E. Regional Variances

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
1	May 9, 2013	Adopted by the NERC Board of Trustees	

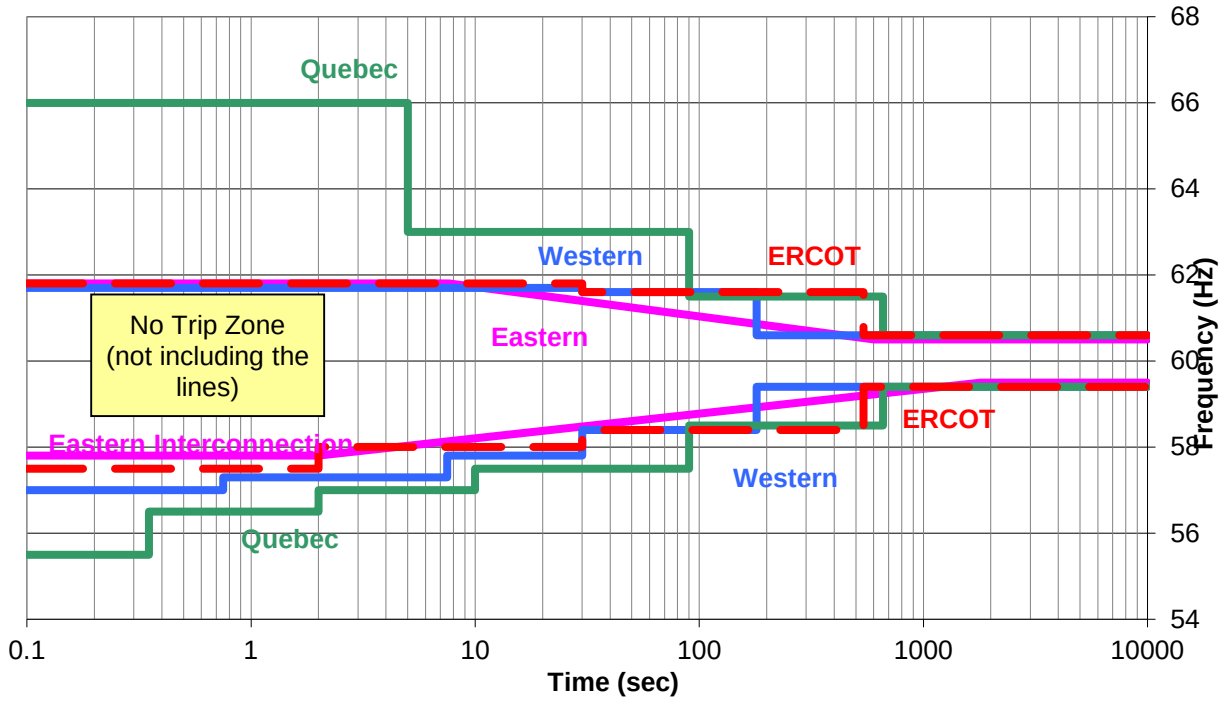
2	TBD	Adopted by the NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources

G. References

1. "The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF)," dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

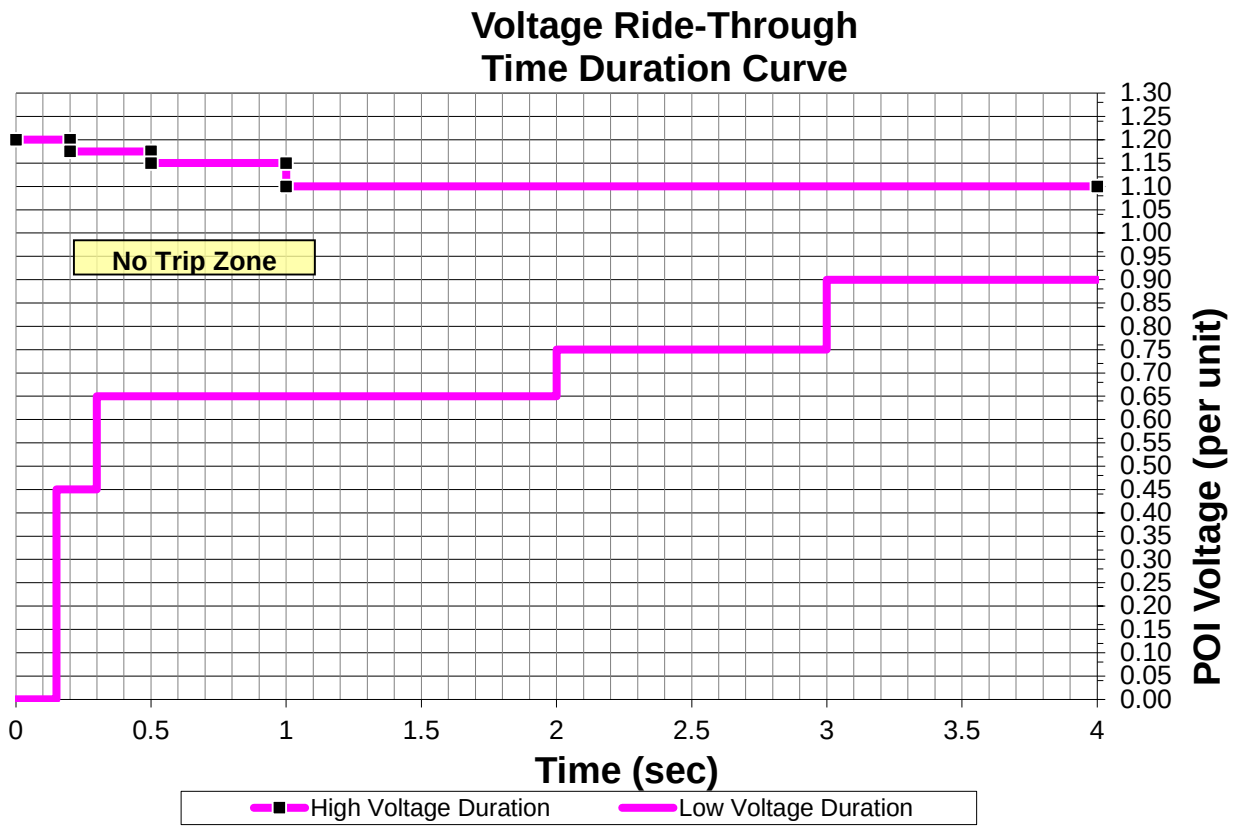
Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (Sec)
>66.0	Instantaneous trip	<55.5	Instantaneous trip
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.5	Instantaneous trip
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024— Attachment 2



Ride Through Duration:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	**Time (sec)**	**Voltage (pu)**	**Time (sec)**
≥1.200	Instantaneous trip	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
    a. All of the units connected to the same transformer are online and operating.
    b. All of the units are at full nameplate real-power output.
    c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
    d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.
3. Initial posting of revised standard PRC-024-2 on November 5, 2014.

Description of Current Draft

PRC-024-~~21(X)~~[1] is proposed for approval to align the applicability section of PRC-024-1 with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 –Standards Applicability for Dispersed Generation Resources standards drafting team recommended changes to the requirements addressing the scope of applicability and also recommended changes to the Reliability Standard Audit Worksheet to address documentation options. ~~Given the timing of concurrent standards development of PRC projects, PRC-024-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-024. If this occurs, PRC-024-1(X) will not go into effect.~~ Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.[2]

Anticipated Actions	Anticipated Date
~~45-day Additional Formal Comment Period with Additional Ballot (if necessary)~~	~~December 2014~~
Final ballot	January 2015
BOT adoption	February 2015

[1] The standard version number included an (X) to indicate the version numbering would be updated, and NERC has since assigned the appropriate version number prior to final ballot.~~currently includes an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to adoption by the NERC Board of Trustees.~~

[2] The terms “dispersed generation resources” and “dispersed power producing resources” are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

1. **Title:** **Generator Frequency and Voltage Protective Relay Settings**
2. **Number:** PRC-024-2~~1(X)~~
3. **Purpose:** Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.
4. **Applicability:**

   4.1. Generator Owner

5. **Effective Date:**

   See the Implementation Plan for PRC-024-2~~this standard~~.

B. Requirements

R1. Each Generator Owner that has generator frequency protective relaying[3] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the "no trip zone" of PRC-024 Attachment 1, subject to the following exceptions:[4] *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

[3] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

[4] For frequency protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to frequency protective relays applied on the individual generating unit of the dispersed power producing resources, as well as frequency protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.

Rationale for Footnotes ~~2~~ 4 and ~~4~~6

The SDT has determined it is appropriate to require that protective relay settings applied on both the individual generating units and aggregating equipment (including any non-Bulk Electric System collection system equipment) are set respecting ~~within~~ the "no-trip zone" referenced in the requirements to maintain reliability of the BES. If any of the protective relay settings applied on these elements of the facility were to be excluded from this standard, the potential would exist for portions of or the entire generating capacity of the dispersed power producing facility to be lost during a voltage or frequency excursion.

R2. Each Generator Owner that has generator voltage protective relaying[3] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection[5]) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2.[6] If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner's study. Requirement R2 is subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

[5] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

[6] For voltage protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to voltage protective relays applied on the individual generating unit of the dispersed power producing resources, as well as voltage protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.

R3. Each Generator Owner shall document each known regulatory or equipment limitation[7] that prevents an applicable generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:

- Identification of a regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.
- Replacement of the equipment causing the limitation with equipment that removes the limitation.
- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.

R4. Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets or other documentation.

M2. Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, dynamic simulation studies or other documentation.

M3. Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.

[7] Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.

M4. Each Generator Owner shall have evidence that it communicated applicable generator protective relay trip settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases, the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner shall retain evidence of compliance with Requirement R1 through R4; for 3 years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, the Generator Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generating unit, failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit, failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	OR The Generator Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.
R4	The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner failed to provide its generator protection trip settings within 150 calendar days of any change to those trip settings. OR The Generator Owner failed to provide trip settings within 150 calendar days of a written request.

E. Regional Variances

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
1	May 9, 2013	Adopted by the NERC Board of Trustees	

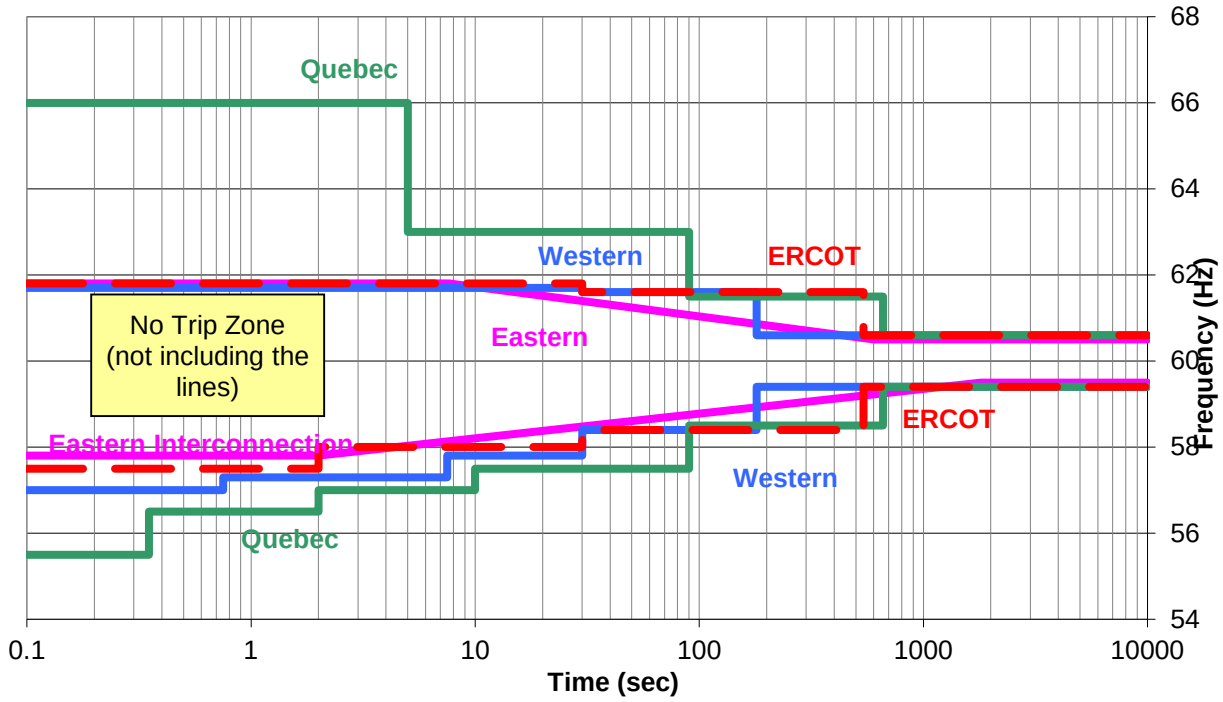
~~1~~	~~March 20, 2014~~	~~FERC Order issued approving PRC-024-1. (Order becomes effective on 7/1/16.)~~	
2	TBD	Adopted by the NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources

G. References

1. "The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF)," dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

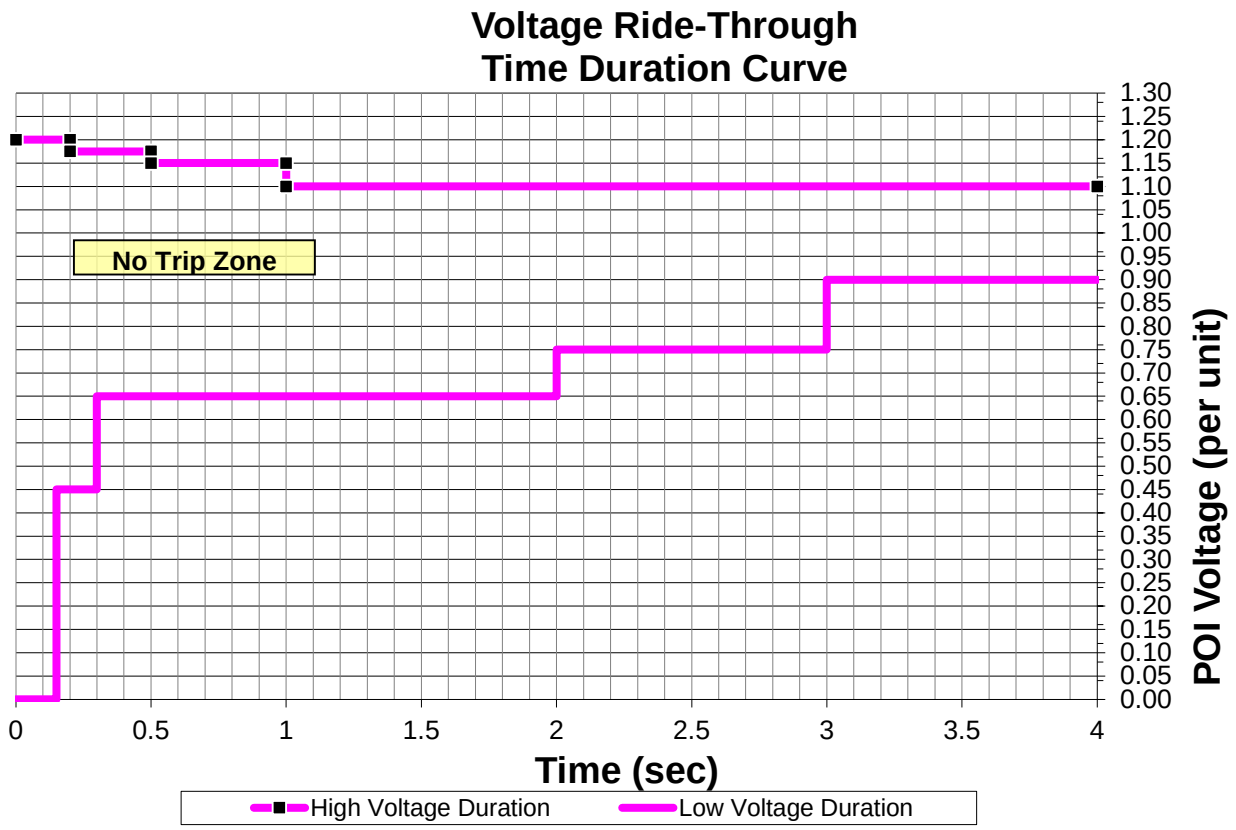
Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (Sec)
>66.0	Instantaneous trip	<55.5	Instantaneous trip
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.5	Instantaneous trip
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024— Attachment 2



Ride Through Duration:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	**Time (sec)**	**Voltage (pu)**	**Time (sec)**
≥1.200	Instantaneous trip	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
    a. All of the units connected to the same transformer are online and operating.
    b. All of the units are at full nameplate real-power output.
    c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
    d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.
3. Initial posting of revised standard PRC-024-2 on November 5, 2014.

Description of Current Draft

PRC-024-21(X)[1] is proposed for approval to align the applicability section of PRC-024-1 with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 –Standards Applicability for Dispersed Generation Resources standards drafting team recommended changes to the requirements addressing the scope of applicability and also recommended changes to the Reliability Standard Audit Worksheet to address documentation options. Given the timing of concurrent standards development of PRC projects, PRC-024-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-024. If this occurs, PRC-024-1(X) will not go into effect. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.[2]

Anticipated Actions	Anticipated Date
Final ballot	January 2015
BOT adoption	February 2015

[1] The standard version number included an (X) to indicate the version numbering would be updated, and NERC has since assigned the appropriate version number prior to final ballot.currently had includes an (X) to indicate the version numbering will be updated, and . Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will since assign the appropriate version number prior to adoption by the NERC Board of Trustees.

[2] The terms “dispersed generation resources” and “dispersed power producing resources” are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

1. **Title:** **Generator Frequency and Voltage Protective Relay Settings**

2. **Number:** PRC-024-21(X)

3. **Purpose:** Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.

4. **Applicability:**

   4.1. Generator Owner

5. **Effective Date:**

   See the Implementation Plan for PRC-024-2this standard.

In those jurisdictions where regulatory approval is required:

By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

In those jurisdictions where regulatory approval is not required:

By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

~~By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

B. Requirements

R1. Each Generator Owner that has generator frequency protective relaying[3] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the "no trip zone" of PRC-024 Attachment 1, subject to the following exceptions:[4] *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

Rationale for Footnotes 24 and 46

The SDT has determined it is appropriate to require that protective relay settings applied on both the individual generating units and aggregating equipment (including any non-Bulk Electric System collection system equipment) are set respectingwithin the "no-trip zone" referenced in the requirements to maintain reliability of the BES. If any of the protective relay settings applied on these elements of the facility were to be excluded from this standard, the potential would exist for portions of or the entire generating capacity of the dispersed power producing facility to be lost during a voltage or frequency excursion.

R2. Each Generator Owner that has generator voltage protective relaying[3] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a

[3] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

[4] For frequency protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to frequency protective relays applied on the individual generating unit of the dispersed power producing resources, as well as frequency protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.

voltage excursion (at the point of interconnection[5]) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2.[6] If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner's study. Requirement R2 is subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

R3. Each Generator Owner shall document each known regulatory or equipment limitation[7] that prevents an applicable generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:

- Identification of a regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.

[5] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

[6] For voltage protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to voltage protective relays applied on the individual generating unit of the dispersed power producing resources, as well as voltage protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.

[7] Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.

- Replacement of the equipment causing the limitation with equipment that removes the limitation.
- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.

R4. Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets or other documentation.

M2. Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, dynamic simulation studies or other documentation.

M3. Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.

M4. Each Generator Owner shall have evidence that it communicated applicable generator protective relay trip settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases, the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where

the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner shall retain evidence of compliance with Requirement R1 through R4; for 3 years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, the Generator Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generating unit, failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit, failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	OR The Generator Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.
R4	The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner failed to provide its generator protection trip settings within 150 calendar days of any change to those trip settings. OR The Generator Owner failed to provide trip settings within 150 calendar days of a written request.

E. Regional Variances

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
1	May 9, 2013	Adopted by the NERC Board of Trustees	

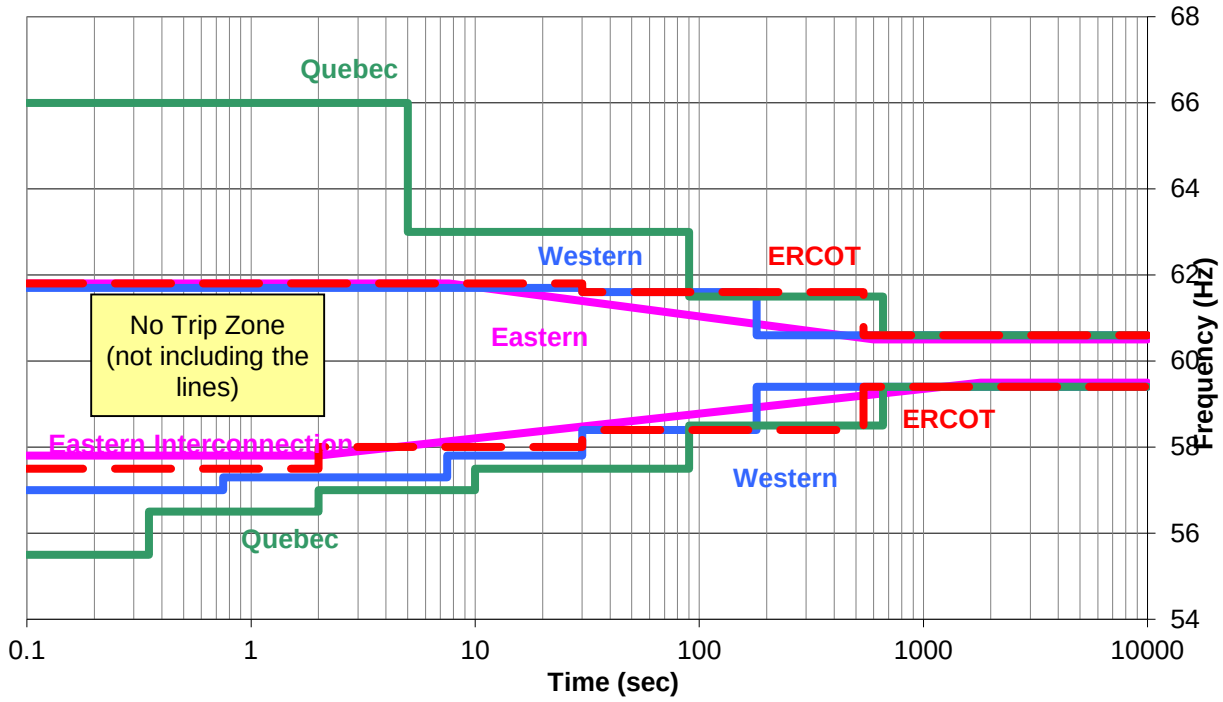
~~1~~	~~March 20, 2014~~	~~FERC Order issued approving PRC-024-1. (Order becomes effective on 7/1/16.)~~	
2	TBD	Adopted by the NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources

G. References

1. "The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF)," dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

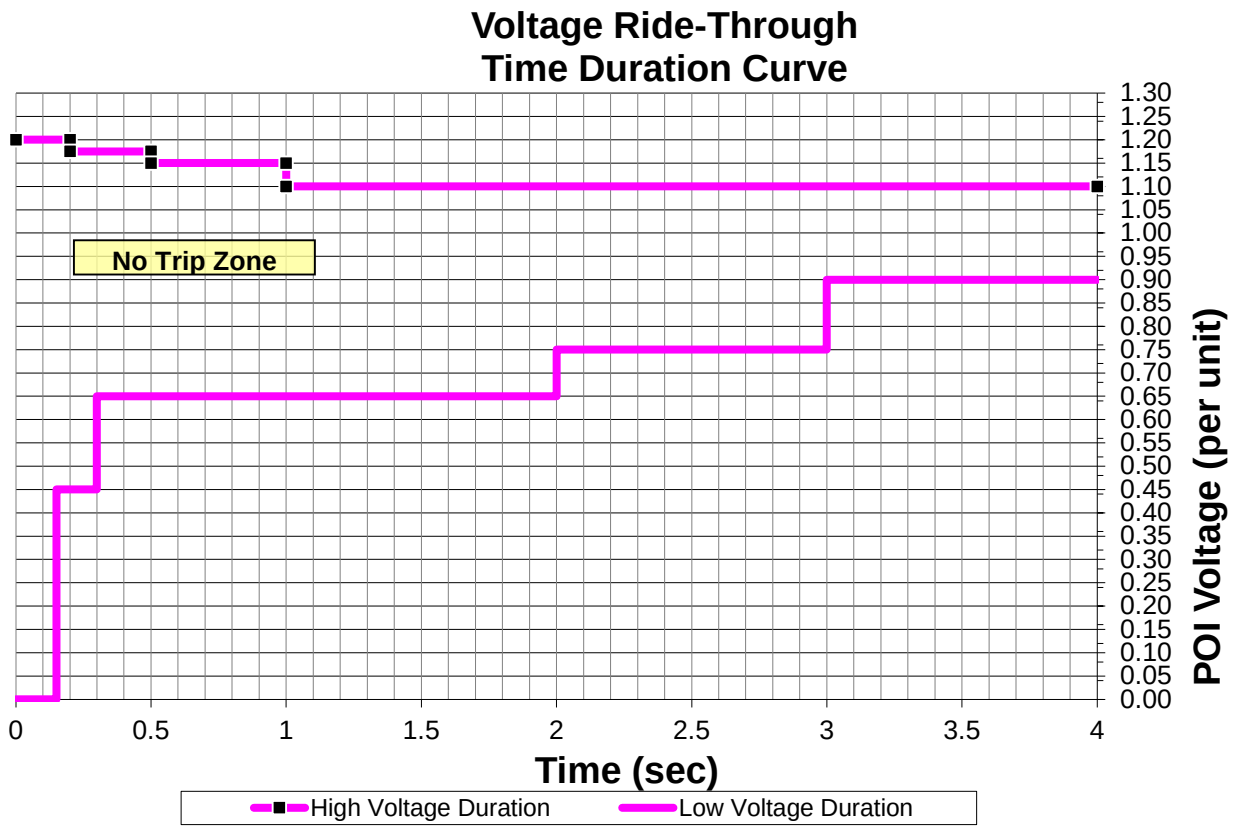
Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (Sec)
>66.0	Instantaneous trip	<55.5	Instantaneous trip
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.5	Instantaneous trip
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024— Attachment 2



Ride Through Duration:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	**Time (sec)**	**Voltage (pu)**	**Time (sec)**
≥1.200	Instantaneous trip	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
    a. All of the units connected to the same transformer are online and operating.
    b. All of the units are at full nameplate real-power output.
    c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
    d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

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Implementation Plan

Dispersed Generation Resources
PRC-001-1.1(ii)

Standards Involved

Approval:

- PRC-001-1.1(ii) – System Protection Coordination

Retirement:

- PRC-001-1.1a – System Protection Coordination (or a successor version of PRC-001-1.1 such as PRC-001-1.1(i))

Prerequisite Approvals:

N/A

Background

In light of the adoption of a revised Bulk Electric System (BES) definition by the NERC Board of Trustees, changes to the applicability of certain Reliability Standards, including PRC-001, are necessary to align the standards with the implementation of the revised BES definition. The standard drafting team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Generation Resources has modified the applicability section and requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed power producing resources in order to ensure the applicability of the standards is consistent with the reliable operation of the BES.[1]

General Considerations

PRC-001-1.1(ii) is proposed for approval to align the applicability of PRC-001-1.1 with the revised definition of the BES. Specifically, the SDT has coordinated with the other SDTs currently reviewing this standard and has recommended revisions to Requirement R3.1 to account for the unique characteristics of dispersed power producing resources.

Effective Date

PRC-001-1.1(ii) shall become effective immediately after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable

[1] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

The existing standard, PRC-001-1.1 (or a successor version of PRC-001-1.1 such as PRC-001-1.1(i)), shall be retired at midnight of the day immediately prior to the Effective Date of PRC-001-1.1(ii).

Applicability:

This standard applies to the following functional entities:

- Transmission Operator
- Generator Operator
- Balancing Authority

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Implementation Plan

Dispersed Generation Resources
PRC-001-1.1(~~X~~ii)

~~The standard version number currently include an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to adoption by the NERC Board of Trustees.~~

Standards Involved

Approval:

- PRC-001-1.1(~~X~~ii) – System Protection Coordination

Retirement:

- PRC-001-1.1a – System Protection Coordination (or a successor version of PRC-001-1.1 such as PRC-001-1.1(i))

Prerequisite Approvals:

N/A

Background

In light of the adoption of a revised Bulk Electric System (BES) definition by the NERC Board of Trustees, changes to the applicability of certain Reliability Standards, including PRC-001, are necessary to align the standards with the implementation of the revised BES definition. The standard drafting team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Generation Resources has modified the applicability section and requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed power producing resources in order to ensure the applicability of the standards is consistent with the reliable operation of the BES.[1]

General Considerations

PRC-001-1.1(~~X~~ii) is proposed for approval to align the applicability of PRC-001-1.1~~a~~ with the revised definition of the BES. Specifically, the SDT has coordinated with the other SDTs currently reviewing this standard and has recommended revisions to Requirement R3.1 to account for the unique characteristics of dispersed power producing resources. ~~Given the timing of concurrent standards development of PRC, TRP, and IRO projects, PRC-001-1.1a may be retired pursuant to an Implementation Plan of a successor version of PRC-001. If this occurs, PRC-001-1.1(X) will not go into effect.~~

Effective Date

[1] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

PRC-001-1.1(~~X~~ii) shall become effective immediately after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

The existing standard, PRC-001-1.1~~a~~ (or a successor version of PRC-001-1.1 such as PRC-001-1.1(i)), shall be retired at midnight of the day immediately prior to the Effective Date of PRC-001-1.1(~~X~~ii).

Applicability:

This standard applies to the following functional entities:

- Transmission Operator
- Generator Operator
- Balancing Authority

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Implementation Plan

Dispersed Generation Resources
PRC-019-2

Standards Involved

Approval:

- PRC-019-2 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Retirement:

- PRC-019-1 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Prerequisite Approvals:

N/A

Background

In light of the adoption of a revised Bulk Electric System (BES) definition by the NERC Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-019, are necessary to align the standards with the implementation of the revised BES definition. The standard drafting team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Generation Resources has modified the applicability section and requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed power producing resources in order to ensure the applicability of the standards is consistent with the reliable operation of the BES.[1]

General Considerations

PRC-019-2 is proposed for approval to align the applicability section of PRC-019-1 with the revised definition of the BES. Specifically, the SDT has recommended revisions to the Facilities section to clarify that facilities that solely regulate voltage at the individual generating unit are subject to the requirements.

Effective Date

[1] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

PRC-019-2 shall become effective on the later of the first day following the Effective Date of PRC-019-1 or immediately after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the later of the first day following the Effective Date of PRC-019-1 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

The existing standard, PRC-019-1, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-019-2.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner that owns synchronous condenser(s)
- Generator Owner

Implementation Plan

All aspects of the Implementation Plan for PRC-019-1 will remain applicable to PRC-019-2 and are incorporated here by reference.

Cross References

The Implementation Plan for the revised definition of "Bulk Electric System" is available here.

The Implementation Plan for PRC-019-1 is available here.

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Implementation Plan

Dispersed Generation Resources
PRC-019-2

Standards Involved

Approval:

- PRC-019-2 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Retirement:

- PRC-019-1 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Prerequisite Approvals:

N/A

Background

In light of the adoption of a revised Bulk Electric System (BES) definition by the NERC Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-019, are necessary to align the standards with the implementation of the revised BES definition. The standard drafting team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Generation Resources has modified the applicability section and requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed power producing resources in order to ensure the applicability of the standards is consistent with the reliable operation of the BES.[1]

General Considerations

PRC-019-2 is proposed for approval to align the applicability section of PRC-019-1 with the revised definition of the BES. Specifically, the SDT has recommended revisions to the Facilities section to clarify that facilities that solely regulate voltage at the individual generating unit are subject to the requirements. ~~Given the timing of concurrent standards development of PRC projects, PRC-019-1 may already be retired pursuant to an Implementation Plan of a successor version of PRC-. If this occurs, PRC-019-2 will not go into effect.~~

[1] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

Effective Date

PRC-019-2 shall become effective on the later of the first day following the Effective Date of PRC-019-1 or immediately after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the later of the first day following the Effective Date of PRC-019-1 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

The existing standard, PRC-019-1, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-019-2.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner that owns synchronous condenser(s)
- Generator Owner

Implementation Plan

All aspects of the Implementation Plan for PRC-019-1 will remain applicable to PRC-019-2 and are incorporated here by reference.

Cross References

The Implementation Plan for the revised definition of "Bulk Electric System" is available here.

The Implementation Plan for PRC-019-1 is available here.

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Implementation Plan

Dispersed Generation Resources
PRC-024-2

Standards Involved

Approval:

- PRC-024-2 – Generator Frequency and Voltage Protective Relay Settings

Retirement:

- PRC-024-1 – Generator Frequency and Voltage Protective Relay Settings

Prerequisite Approvals:

N/A

Background

In light of the adoption of a revised Bulk Electric System (BES) definition by the NERC Board of Trustees, changes to the applicability of certain Reliability Standards, including PRC-024, are necessary to align the standards with the revised BES definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Generation Resources has modified the applicability section or requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the BES.

General Considerations

PRC-024-2 is proposed for approval to align the applicability of PRC-024-1 with the revised definition of the BES. Specifically, the SDT recommended changes to the requirements addressing the scope of applicability and also recommended changes to the Reliability Standard Audit Worksheet to address documentation options.

Effective Date

PRC-024-2 shall become effective on the later of the first day following the Effective Date of PRC-024-1 or immediately after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the later of the first day following the Effective Date of PRC-024-1 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

The existing standard, PRC-024-1, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-024-2.

Applicability:

This standard applies to the following functional entities:

- Generator Owner

Implementation Plan

All aspects of the Implementation Plan for PRC-024-1 will remain applicable to PRC-024-2 and are incorporated here by reference.

Cross References

The Implementation Plan for the revised definition of "Bulk Electric System" is available here.

The Implementation Plan for PRC-024-1 is available here.

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Implementation Plan

Dispersed Generation Resources

PRC-024-~~1(X)~~2

~~The standard version numbers currently include an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to adoption by the NERC Board of Trustees.~~

Standards Involved

Approval:

- PRC-024-~~1(X)~~2 – Generator Frequency and Voltage Protective Relay Settings

Retirement:

- PRC-024-1 – Generator Frequency and Voltage Protective Relay Settings

Prerequisite Approvals:

N/A

Background

In light of the adoption of a revised Bulk Electric System (BES) definition by the NERC Board of Trustees, changes to the applicability of certain Reliability Standards, including PRC-024, are necessary to align the standards with the revised BES definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Generation Resources has modified the applicability section or requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the BES.

General Considerations

PRC-024-~~1(X)~~2 is proposed for approval to align the applicability of PRC-024-1 with the revised definition of the BES. Specifically, the SDT recommended changes to the requirements addressing the scope of applicability and also recommended changes to the Reliability Standard Audit Worksheet to address documentation options. ~~Given the timing of concurrent standards development of PRC projects, PRC-024-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-024. If this occurs, PRC-024-1(X) will not go into effect.~~

Effective Date

PRC-024-~~1(X)~~2 shall become effective on the later of the first day following the Effective Date of PRC-024-1 or immediately after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the later of the first day following the Effective

Date of PRC-024-1 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:
The existing standard, PRC-024-1, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-024-~~1(X)~~2.

Applicability:
This standard applies to the following functional entities:

- Generator Owner

Implementation Plan
All aspects of the Implementation Plan for PRC-024-1 will remain applicable to PRC-024-~~(X)~~2 and are incorporated here by reference.

Cross References
The Implementation Plan for the revised definition of "Bulk Electric System" is available here.

The Implementation Plan for PRC-024-1 is available here.

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Standards Authorization Request Form

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

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

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Application of certain GO/GOP Reliability Standards and Requirements to Dispersed Generation		
Date Submitted:	10/1/2013		
SAR Requester Information			
Name:	Jennifer Sterling-Exelon, Gary Kruempel-MidAmerican, Allen Schriver-NextEra Energy, Inc., Brian Evans-Mongeon-Utility Services Inc.		
Organization:	Exelon, MidAmerican, NextEra Energy, Utility Services Inc.		
Telephone:	(630) 437-2764 – primary contact	E-mail:	jennifer.sterling@exeloncorp.com primary contact
SAR Type (Check as many as applicable)			
☐ New Standard ☒ Revision to existing Standard		☐ Withdrawal of existing Standard ☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
The industry is requesting that the application section of certain GO/GOP Reliability Standards or the requirements of certain GO/GOP Reliability Standards be revised in order to ensure that the Reliability Standards are not imposing requirements on dispersed generation that are unnecessary and/or counterproductive to the reliable operation of the Bulk Electric System (BES). For purposes of this SAR, dispersed generation are those resources that aggregate to a total capacity greater than 75 MVA (gross

SAR Information
nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. This request is related to the proposed new definition of the Bulk Electric System (BES) from Project 2010-17, that results in the identification of elements of new dispersed generation facilities that if included under certain Reliability Standards may result in a detriment to reliability or be technically unsound and not useful to the support of the reliable operation of the BES .
Purpose or Goal (How does this request propose to address the problem described above?):
The goal of the request is to revise the applicability of GO/GOP Reliability Standards or the Requirement(s) of GO/GOP Reliability Standards to recognize the unique technical and reliability aspects of dispersed generation, given the proposed new definition of the BES.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objective of the revisions to the applicability section and/or Requirements of certain GO/GOP Reliability Standards is to ensure that these revisions are approved by the Board of Trustees and applicable regulatory agencies prior to the effective date for newly identified elements under the proposed BES definition (i.e., June 2016).
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The scope of this SAR involves revisions to the applicability section of the following GO/GOP Reliability Standard applicability sections and/or Reliability Standard Requirements: (a) PRC-005-2 (-3); (b) FAC-008-3; (c) PRC-023-3/PRC-025-1; (d) PRC-004-2a (-3) ; and (e) VAR-002-2 so it is clear what, if any, requirements should apply to dispersed generation. Also, IRO,MOD, PRC or TOP Standards that require outage and protection and control coordination, planning, next day study or real time data or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities and reporting are conducted at the point of aggregation to 75 MVA, and not at an individual turbine, inverter or unit level for dispersed generation. This scope would also include development of a technical guidance paper for standard drafting teams developing new or revised Standards, so that they do not incorrectly apply requirements to dispersed generation unless such an application is technically sound and promotes the reliable operation of the BES. To the extent, there are existing Reliability Standard Drafting Teams that have the expertise and can make the requested changes prior to the compliance date of newly identified assets under the BES definition (i.e., June 2016), those projects may be assigned the required changes as opposed to creating new projects.

SAR Information
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

The following description and technical justification(including an assessment of reliability impacts) is provided for the standard drafting teams to execute the SAR for each applicable Standard.

PRC-005-2

Testing and maintenance of protection and control equipment for dispersed generation should start at the point of aggregation to 75 MVA. Manufacturers of dispersed generation turbines and solar panels recommend against specific testing and maintenance regimes for protection and control equipment at the dispersed generation turbine and panel level. In fact it is counterproductive to implement protection and control at the individual turbine, solar panel, or unit level. Instead this is best done at an aggregated level. Therefore, PRC-005 should indicate that the standard applies at the point of aggregation to at 75 MVA or greater for dispersed generation. This change would clarify that the facility section 4.2.5.3 is the section that would apply to dispersed generating facilities and that the remaining sections would not apply.

FAC-008-3

For dispersed generation, it is unclear if in FAC-008-3 the term “main step up transformer” refers to the padmount transformer at the base of the windmill tower or to the main aggregating transformer that steps up voltage to transmission system voltage. From a technical standpoint, it should be the point of aggregation at 75 MVA or above that is subject to this standard for dispersed generation, such as wind. It is at the point of aggregation at 75 MVA or above that facilities ratings should start, since it is this injection point at which a planner or operator of the system is relying on the amount of megawatts the dispersed generation is providing with consideration of the most limiting element. To require facility ratings at for each dispersed turbine, panel or generating unit is not useful to a planner or operator of the system, and, therefore, FAC-008-3 should be revised to be clear that facility ratings start at the point of aggregation at 75 MVA or above for dispersed generation.

SAR Information

Also consider that the BES definition specifically excludes collector system equipment at less than 75 MVA from being included in the BES. Thus, those portions of the collector systems that handle less than 75 MVA are not BES "Facilities," and, therefore, need not be evaluated per R1 or R2. Given this, there seems to be no technical value to conduct facility ratings for individual dispersed generation turbines, generating units and panels.

PRC-023-3/PRC-025-1

In keeping with the registration criteria for Generator Owners as well as the proposed BES Definition, the 75MVA point of aggregation should be the starting point for application of relay loadability requirements.

PRC-004-2

There is no technical basis to claim that misoperation analysis, corrective action plan implementation and reporting for dispersed generation at the turbine, generating unit or panel level is needed for the reliable operation of the BES. Similar to the statements above, the appropriate point to require misoperation analysis, corrective action plan implementation and reporting is at the point of aggregation at 75 MVA and above.

VAR-002-2

Voltage control for some types of dispersed generating facilities is accomplished by a controller that is able to adjust either generating unit controls or discrete reactive components to provide transmission system voltage adjustment. The VAR-002 standard should be modified to allow this type of control for dispersed generation facilities under the requirements of the standard.

General review of IROs, MODs, PRCs, TOPs

IRO, MOD, PRC or TOP Standards that require outage and protection and control coordination, planning, next day study or real time data or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities are conducted at the point of aggregation at 75 MVA, and not an individual turbine, generating unit or panel level for dispersed generation. Unless this clarity is provided applicability at a finer level of granularity related to dispersed generation may be seen as required and such granularity will result in activities that have no benefit to

SAR Information
reliable operation of the BES. Furthermore applicability at a finer level of granularity will result in uneeded and ineffective collection, analysis, and reporting activities that may result in a detriment to reliability.

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

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

Reliability and Market Interface Principles		
Applicable Reliability Principles (Check all that apply).		
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.	
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.	
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.	
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.	
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.	
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.	
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.	
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.	
Does the proposed Standard comply with all of the following Market Interface Principles?		Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.		Yes

Reliability and Market Interface Principles	
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
PRC-005-2, FAC-008-3, PRC-023-3/PRC-025-1/PRC-004-2a, VAR-002-2b and various IRO, MOD, PRC and TOP Standards	See explanation under technical analysis.

Related SARs	
SAR ID	Explanation
	N/A

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2014-01 Standards Applicability for Dispersed Generation Resources
PRC-001-1.1(ii), PRC-019-2, and PRC-024-2

Final Ballots Now Open through January 22, 2015

Now Available

Final ballots for three Project 2014-01 Standards Applicability for Dispersed Generation Resources medium-priority Reliability Standards as identified in the draft White Paper prepared by the Project 2014-01 drafting team are open through **8 p.m. Eastern, Thursday, January 22, 2015.**

The standards being balloted are:
- PRC-001-1.1(X) - System Protection Coordination
- PRC-019-2 - Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection
- PRC-024-1(X) - Generator Frequency and Voltage Protective Relay Settings

Background information for this project can be found on the project page.

Instructions for Balloting
In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a vote during the last ballot window may cast a vote in the final ballot window. If a ballot pool member cast a vote in the previous ballot and does not participate in the final ballot, that member's vote will be carried over in the final ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the standards by clicking here.

Next Steps
The voting results for the standards will be posted and announced after the ballot window closes. If approved, they will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities**.**

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Katherine Street, Standards Developer, or at 404-446-9702.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
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Atlanta, GA 30326
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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2014-01 Standards Applicability for Dispersed Generation Resources
PRC-001-1.1(ii), PRC-019-2, and PRC-024-2

Final Ballot Results

Now Available

Final ballots for three Project 2014-01 Standards Applicability for Dispersed Generation Resources medium-priority Reliability Standards as identified in the draft White Paper prepared by the Project 2014-01 drafting team concluded at **8 p.m. Eastern, Thursday, January 22, 2015.**

The standards are as follows:

- PRC-001-1.1(ii) – System Protection Coordination
- PRC-019-2 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection
- PRC-024-2 – Generator Frequency and Voltage Protective Relay Settings

The standards achieved a quorum and received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Ballot Results	
Standard	**Quorum /Approval**
PRC-001-1.1(ii)	89.27% / 93.99%
PRC-019-2	89.30% / 94.03%
PRC-024-2	89.52% / 95.82%

Background information for this project can be found on the project page.

Next Steps

The standards will be submitted to the NERC Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Katherine Street, Standards Developer, or at 404-446-9702.

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Ballot Results	
Ballot Name:	Project 2014-01-DGR-PRC-001-1.1(ii)_Final_Ballot
Ballot Period:	1/13/2015 - 1/22/2015
Ballot Type:	Final
Total # Votes:	316
Total Ballot Pool:	354
Quorum:	**89.27 % The Quorum has been reached**
Weighted Segment Vote:	93.99 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	91	1	60	0.938	4	0.063	0	14	13
2 - Segment 2	8	0.4	4	0.4	0	0	0	2	2
3 - Segment 3	82	1	61	0.953	3	0.047	0	14	4
4 - Segment 4	27	1	20	1	0	0	0	6	1
5 - Segment 5	79	1	52	0.881	7	0.119	0	9	11
6 - Segment 6	52	1	37	0.925	3	0.075	0	7	5
7 - Segment 7	1	0	0	0	0	0	0	0	1
8 - Segment 8	5	0.5	4	0.4	1	0.1	0	0	0
9 - Segment 9	3	0.3	3	0.3	0	0	0	0	0

10 - Segment 10	6	0.5	5	0.5	0	0	0	0	1
Totals	**354**	**6.7**	**246**	**6.297**	**18**	**0.404**	**0**	**52**	**38**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson		
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Mike Smith	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	

1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Joseph A Smith	Negative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Steven C Cobb	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Tacoma Power	John Merrell	Abstain	
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Steven Johnson		
1	Wind Energy Transmission Texas, LLC	Julius Horvath		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist		
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Avista Corp.	Scott J Kinney	Abstain	
3	Basin Electric Power Cooperative	Jeremy Voll	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Beaches Energy Services	Steven Lancaster	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Leesburg	Chris Adkins	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	Colorado Springs Utilities	Jean Mueller	Negative	

3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Negative	
3	CPS Energy	Jose Escamilla		
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Abstain	
3	FirstEnergy Corp.	Richard S Hoag	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Fort Pierce Utilities Authority	Thomas Parker	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Seth Shoemaker	Affirmative	
3	N.W. Electric Power Cooperative, Inc.	John Stickley	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Abstain	
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	
3	Puget Sound Energy, Inc.	Andrea Basinski	Affirmative	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Power	Marc Donaldson	Abstain	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	

4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Abstain	
4	DTE Electric	Daniel Herring	Abstain	
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Fort Pierce Utilities Authority	Javier Cisneros	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Keys Energy Services	Stan T Rzad	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	Basin Electric Power Cooperative	Mike Kraft	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources Services	Randall C Heise	Affirmative	
5	DTE Electric	Mark Stefaniak	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Abstain	

5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Yuguang Xiao	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Northern Indiana Public Service Co.	Michael D Melvin	Abstain	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		
5	PPL Generation LLC	Annette M Bannon	Negative	
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Abstain	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tennessee Valley Authority	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Negative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Abstain	
6	Luminant Energy	Brenda Hampton	Abstain	

6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	New York State Electric & Gas Corp.	Julie S King	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	COMMENT RECEIVED
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Abstain	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
6	Westar Energy	Tiffany Lake	Affirmative	
6	Western Area Power Administration - UGP Marketing	Mark Messerli	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway		
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake		
8		Roger C Zaklukiewicz	Affirmative	
8		David L Kiguel	Negative	
8		Debra R Warner	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	City of Vero Beach	Ginny Beigel	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Bob Reynolds		
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Legal and Privacy : 404.446.2560 voice : 404.467.0474 fax : 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

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Ballot Results	
Ballot Name:	Project 2014-01-DGR-PRC-019-2_Final_Ballot
Ballot Period:	1/13/2015 - 1/22/2015
Ballot Type:	Final
Total # Votes:	317
Total Ballot Pool:	355
Quorum:	**89.30 % The Quorum has been reached**
Weighted Segment Vote:	94.03 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	91	1	60	0.938	4	0.063	0	15	12
2 - Segment 2	7	0.2	1	0.1	1	0.1	0	3	2
3 - Segment 3	83	1	61	0.968	2	0.032	0	15	5
4 - Segment 4	27	1	20	0.952	1	0.048	0	5	1
5 - Segment 5	79	1	52	0.897	6	0.103	0	10	11
6 - Segment 6	52	1	39	0.951	2	0.049	0	6	5
7 - Segment 7	1	0	0	0	0	0	0	0	1
8 - Segment 8	5	0.5	5	0.5	0	0	0	0	0
9 - Segment 9	3	0.3	3	0.3	0	0	0	0	0

10 - Segment 10	7	0.6	6	0.6	0	0	0	0	1
Totals	**355**	**6.6**	**247**	**6.206**	**16**	**0.395**	**0**	**54**	**38**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Negative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson		
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Abstain	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Mike Smith	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	

1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Joseph A Smith	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Steven C Cobb	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Tacoma Power	John Merrell	Negative	
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Steven Johnson		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	ISO New England, Inc.	Matthew F Goldberg	Negative	COMMENT RECEIVED
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist		
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Avista Corp.	Scott J Kinney	Abstain	
3	Basin Electric Power Cooperative	Jeremy Voll	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Beaches Energy Services	Steven Lancaster	Affirmative	
3	Blue Ridge Electric	James L Layton		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Leesburg	Chris Adkins	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	

3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Negative	
3	CPS Energy	Jose Escamilla		
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Abstain	
3	FirstEnergy Corp.	Richard S Hoag	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Fort Pierce Utilities Authority	Thomas Parker	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Abstain	
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Seth Shoemaker	Affirmative	
3	N.W. Electric Power Cooperative, Inc.	John Stickley	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Abstain	
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Andrea Basinski	Affirmative	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Power	Marc Donaldson	Negative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	

4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Abstain	
4	DTE Electric	Daniel Herring	Abstain	
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Fort Pierce Utilities Authority	Javier Cisneros	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Keys Energy Services	Stan T Rzad	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Negative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	Basin Electric Power Cooperative	Mike Kraft	Abstain	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources Services	Randall C Heise	Affirmative	
5	DTE Electric	Mark Stefaniak	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		

5	Lower Colorado River Authority	Dixie Wells	Abstain	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Yuguang Xiao	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Northern Indiana Public Service Co.	Michael D Melvin	Abstain	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tennessee Valley Authority	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Negative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Abstain	
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	

6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	New York State Electric & Gas Corp.	Julie S King	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
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6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
6	Westar Energy	Tiffany Lake	Affirmative	
6	Western Area Power Administration - UGP Marketing	Mark Messerli	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway		
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake		
8		Roger C Zaklukiewicz	Affirmative	
8		David L Kiguel	Affirmative	
8		Debra R Warner	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	City of Vero Beach	Ginny Beigel	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Bob Reynolds		
10	Texas Reliability Entity, Inc.	Derrick Davis	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Ballot Results	
Ballot Name:	Project 2014-01-DGR-PRC-024-2_Final_Ballot
Ballot Period:	1/13/2015 - 1/22/2015
Ballot Type:	Final
Total # Votes:	316
Total Ballot Pool:	353
Quorum:	**89.52 % The Quorum has been reached**
Weighted Segment Vote:	95.82 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	90	1	58	0.935	4	0.065	0	16	12
2 - Segment 2	7	0.2	2	0.2	0	0	0	3	2
3 - Segment 3	82	1	59	0.937	4	0.063	0	15	4
4 - Segment 4	27	1	20	0.952	1	0.048	0	5	1
5 - Segment 5	79	1	56	0.949	3	0.051	0	9	11
6 - Segment 6	52	1	39	0.951	2	0.049	0	6	5
7 - Segment 7	2	0.1	1	0.1	0	0	0	0	1
8 - Segment 8	5	0.5	5	0.5	0	0	0	0	0
9 - Segment 9	3	0.3	3	0.3	0	0	0	0	0

10 - Segment 10	6	0.5	5	0.5	0	0	0	0	1
Totals	**353**	**6.6**	**248**	**6.324**	**14**	**0.276**	**0**	**54**	**37**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson		
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Abstain	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Abstain	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Mike Smith	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Negative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	

1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Joseph A Smith	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Steven C Cobb	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Tacoma Power	John Merrell	Negative	
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Steven Johnson		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist		
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Avista Corp.	Scott J Kinney	Abstain	
3	Basin Electric Power Cooperative	Jeremy Voll	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Beaches Energy Services	Steven Lancaster	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Leesburg	Chris Adkins	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	

3	Consumers Energy Company	Gerald G Farringer	Negative	
3	CPS Energy	Jose Escamilla		
3	Dominion Resources, Inc.	Connie B Lowe	Negative	
3	DTE Electric	Kent Kujala	Abstain	
3	FirstEnergy Corp.	Richard S Hoag	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Fort Pierce Utilities Authority	Thomas Parker	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Abstain	
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Seth Shoemaker	Affirmative	
3	N.W. Electric Power Cooperative, Inc.	John Stickley	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Abstain	
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Andrea Basinski	Affirmative	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Power	Marc Donaldson	Negative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	

4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Abstain	
4	DTE Electric	Daniel Herring	Abstain	
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Fort Pierce Utilities Authority	Javier Cisneros	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Keys Energy Services	Stan T Rzad	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	Basin Electric Power Cooperative	Mike Kraft	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources Services	Randall C Heise	Negative	
5	DTE Electric	Mark Stefaniak	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Abstain	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Yuguang Xiao	Affirmative	

5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Abstain	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tennessee Valley Authority	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Abstain	
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	New York State Electric & Gas Corp.	Julie S King	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	

6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	COMMENT RECEIVED
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
6	Westar Energy	Tiffany Lake	Affirmative	
6	Western Area Power Administration - UGP Marketing	Mark Messerli	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway		
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake		
7	Occidental Chemical	Venona Greaff	Affirmative	
8		David L Kiguel	Affirmative	
8		Debra R Warner	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	City of Vero Beach	Ginny Beigel	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Bob Reynolds		
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Account Log-In/Register

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

March 20, 2015

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: Informational Filing, Frequency Response Annual Analysis
Docket No. RM13-11-000

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits its 2014 Frequency Response Annual Analysis report for the administration and support of proposed Reliability Standard BAL-003-1 – Frequency Response and Frequency Bias Setting ("Report"). The Report attached hereto provides an update to the statistical analyses and calculations contained in the 2012 Frequency Response Initiative Report included as Exhibit F to the March 29, 2013 NERC petition for approval of proposed Reliability Standard BAL-003-1.

Specifically, the Report contains the analysis and annual recommendations for the calculation of the Interconnection Frequency Response Obligations (IFROs). The Report also analyzes: (i) the frequency events occurring between January 1, 2011, and May 31, 2014, and the interconnection frequency characteristics for the period January 1, 2011 through December 31, 2013, to determine appropriate adjustment factors for calculating the IFROs; (ii) the trends in primary Frequency Response sustainability or withdrawal throughout the frequency events; and (iii) frequency anomalies discovered in the 1-second frequency data used as the basis for calculating starting frequencies.

Dynamic simulations of the Eastern, Western, and ERCOT Interconnections for the recommended IFROs showed those levels of primary Frequency Response to be adequate to avoid tripping of the first stage of the interconnection UFLS systems. Light-load cases were used for the analyses, as proposed in Paragraph 41 of the NOPR. Evaluation of field trial data regarding the use of a linear regression method for calculating the Balancing Authority Frequency Response Measure is not included in the Report, but is currently ongoing.

The Frequency Response performance for all four interconnections from 2011 through 2013 exhibits stable trends. No changes are proposed to the procedures recommended in the 2012 Frequency Response Initiative Report.

NERC is not requesting any Commission action on the instant filing. NERC respectfully requests that the Commission accept this filing for informational purposes only.

Respectfully submitted,

/s/ Holly A. Hawkins
Holly A. Hawkins

Counsel for North American Electric Reliability Corporation

cc: Official service list in Docket No. RM13-11-000

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2014 Frequency Response Annual Analysis

February 2015

RELIABILITY | ACCOUNTABILITY






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Atlanta, GA 30326
404-446-2560 | www.nerc.com

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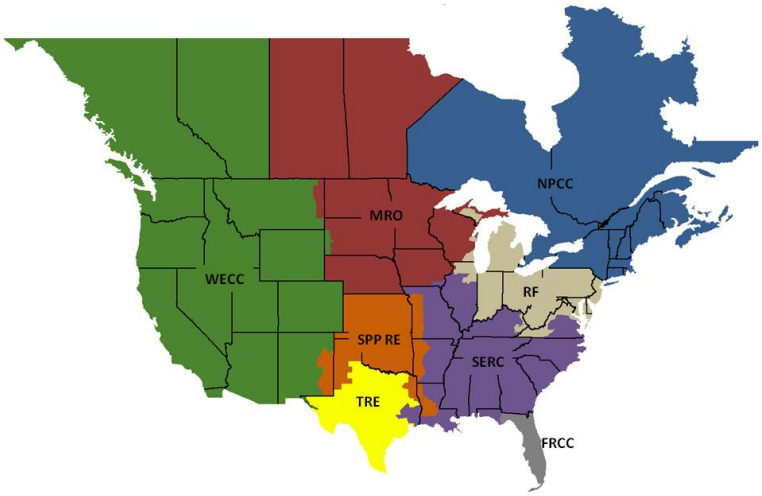
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Preface

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

The North American BPS is divided into eight Regional Entities (RE), as shown in the map and corresponding table below.



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

This Report

This report is the 2014 annual analysis of frequency response performance for the administration and support of NERC Reliability Standard BAL-003-1 – Frequency Response and Frequency Bias Setting. It provides an update to the statistical analyses and calculations contained in the *2012 Frequency Response Initiative Report* approved by the NERC Resources Subcommittee and Operating Committee and accepted by the NERC Board of Trustees. No changes are proposed to the procedures recommended in that report.

Normally, this report would be published in the fall, but it was severely delayed by data problems in the frequency data used for the analysis.

This report, prepared by NERC staff,[1] contains the analysis and annual recommendations for the calculation of the Interconnection Frequency Response Obligation (IFRO) for each of the four electrical interconnections of North America for the operational year 2015 (December 2014 through November 2015). This includes:

- Statistical analysis of the interconnection frequency characteristics for the period January 1, 2011, through December 31, 2013.[2]
- Analysis of the interconnection frequency response performance for frequency events occurring between January 1, 2011, and May 31, 2014, to determine appropriate adjustment factors for calculating the IFROs.
- Dynamics analysis of the recommended IFROs.

This report also includes:

- Analysis of frequency anomalies discovered in the one-second frequency data used as the basis for calculating starting frequencies.
- Analysis of outlier events in frequency response performance contained in the *State of Reliability 2014* report for the Eastern Interconnection.
- Recommendations for additional frequency analysis and proposed changes to the detection and selection of frequency events for the ALR 1–12 Frequency Response metric.

This report was approved by the Resources Subcommittee on January 29, 2015.

This report was approved by the Operating Committee on February 19, 2015, via e-mail ballot.

[1] Prepared by the Reliability Initiatives and System Analysis (RISA) and Performance Analysis (PA) sections of the Reliability Assessment and Performance Analysis group (RAPA).

[2] From the *State of Reliability 2014* report, available at: http://www.nerc.com/pa/RAPA/PA/Pages/default.aspx.

Executive Summary

Recommendations

The following are the recommended parameters and adjustments to use when calculating the IFROs for the 2015 frequency response period (December 2014 through November 2015) during the BAL-003-1 field trial.

In accordance with the BAL-003-1 detailed implementation plan (and as a condition of approval by the Resources Subcommittee and the Operating Committee), these analyses are to be performed annually and the results published by November 15 each year, starting in 2015.

1. No changes are proposed to the procedures recommended in the *2012 Frequency Response Initiative Report*.

2. The IFROs for operating year 2015 (December 2014 through November 2015) are calculated as shown in Table A.

Table A: Recommended IFROs

	Eastern (EI)	Western (WI)	ERCOT (TI)	Québec (QI)	Units
Starting Frequency	59.974	59.968	59.965	59.968	Hz
Max. Allowable Delta Frequency	0.444	0.273	0.391	0.927	Hz
Resource Contingency Protection Criteria	4,500	2,626	2,750	1,700	MW
Credit for LR	–	150	909	–	MW
IFRO[3]	**-1,014**	**-906**	**-471**	**-183**	**MW/0.1Hz**
Absolute Value of IFRO	**1,014**	**906**	**471**	**183**	**MW/0.1Hz**
Absolute Value of Current Interconnection Frequency Response Performance[4]	2,309	1,491	810	603	MW/0.1Hz
2015 IFRO as a % of Interconnection Load[5]	0.16	0.58	0.68	0.48	

3. A Value B to Point C prime adjustment (BC'_{ADJ}) of 17.4 mHz should continue to be made to the Eastern Interconnection allowable delta frequency to compensate for the predominant withdrawal of primary frequency response exhibited in that interconnection. The BC'_{ADJ} was introduced in the *2012 Frequency Response Initiative Report* analysis of the Eastern Interconnection frequency response. Analysis of the frequency events for that interconnection from January 2011 through May 2014 showed a lower nadir

[3] Refer to the IFRO Formulae section of this report for further details on the calculation

[4] Based on 2014 Interconnection Frequency Response Performance from Appendix B of the *State of Reliability 2014* report, reflecting corrections to the ALR 1–12 metric events in the Eastern Interconnection. By interconnection:
EI = -2,349 MW / 0.1Hz, WI = -1,514 MW / 0.1Hz, TI = -612 MW / 0.1Hz, and QI = -575 MW/0.1 Hz.

[5] Interconnection projected Total Internal Demands from the *2014 NERC Long-Term Reliability Assessment* (2015 summer demand):
EI = 617,372 MW, WI = 156,423 MW, TI = 69,057 MW, and QI (2014-2015 winter demand) = 38,316 MW.

(Point C') for the events that typically occur in the T+52 to T+65 second time frame, beyond the measurements of Point C or Value B. Similar analysis of frequency events in the Western, ERCOT, and Québec Interconnections showed that any later nadirs occurred within the time frames of the measurements of Point C or Value B. Therefore, no BC'_{ADJ} is necessary for those interconnections.

4. Monthly processing of one-second data and weekly review of frequency event candidates for both ALR 1–12 and BAL-003-1 are recommended to discover problems sooner and ensure consistency in event selection.

5. The process for selecting ALR 1–12 events should be carefully reviewed and analyzed prior to the publication of the *2015 State of Reliability* report.

Findings

1. The frequency response performance exhibits stable trends for all four interconnections from 2011 through 2013.

2. Frequency event selection errors during 2013 were found in the ALR 1–12 Frequency Response metric presented in the *State of Reliability 2014* report. This resulted in 19 Eastern Interconnection events being eliminated from the ALR 1–12 events. The analysis for the Eastern Interconnection is corrected in this report and that correction has been made to the NERC Reliability Indicators dashboard.[6]

3. Frequency step-change[7] anomalies were found in the 2013 one-second Eastern Interconnection frequency data used to determine the starting frequency for the IFRO calculations. The problem was traced back to toggling back and forth between two data sources in the calculation of the one-second averaged data. The entire 2013 one-second database was recalculated to correct the problem.

4. An error was discovered in several start times for frequency events in the Eastern, Western, ERCOT, and Québec Interconnections starting in July 2013.[8] The problem arose from a sign error in an adjustment factor used to remove a time skew inherent in the high-speed metrology: instead of removing the time skew, the adjustment factor was doubling it. This impacted several of the adjustment factors used in the IFRO calculation related to Point C. The error was corrected and all timing of frequency events have been recalculated for this and future analyses.

5. Several sources of sub-second data were determined to be in maintenance/offline mode, which resulted in the provision of inaccurate sub-second frequency data. The sub-second data was corrected by replacing the erroneous sources with data from operational data sources available during frequency events.

6. For the ERCOT Interconnection IFRO calculation, credit for load resources was increased from 895 MW used in the 2013 calculations to a statistically determined 909 MW. This represents the amount of contractual 1,400 MW load resource that is available 95 percent of the time. Additionally, the ERCOT CB_R ratio increased significantly due to changes in the interconnection's frequency response performance in 2013. That change increased the ERCOT Interconnection IFRO by 58 MW/0.1 Hz. ERCOT has been experiencing a displacement of coal-fired generation by gas-fired combined cycle units in their dispatch due to lower prices for natural gas. While the combined-cycle units are responsive in the Value B calculation time frame (+20 to +52 seconds), they are slower than the steam units to respond in the arresting power time frame (+0 to +20 seconds). This results in a similar Value B response but a lower

[6] Located at: http://www.nerc.com/pa/RAPA/ri/Pages/InterconnectionFrequencyResponse.aspx
[7] Abrupt changes in frequency.
[8] This problem did not affect the 2013 IFRO calculations because it began after the time frame used in those calculations.

Point C nadir, which increases the CB_R ratio as the performance in 2013–2014 displaces the older performance characteristics.

7. Dynamics simulations of the Eastern, Western, and ERCOT Interconnections for the recommended IFROs showed those levels of primary frequency response to be adequate to avoid tripping of the first stage of the interconnection UFLS systems. Light-load cases were used for all three of these analyses.

Frequency Response Performance Analysis

Every year, NERC analyzes the frequency response performance of the four interconnections in the *State of Reliability* report. The following charts and statistics are drawn from the *State of Reliability 2014* report and the Interconnection Frequency Response from the NERC Reliability Indicators dashboard.[9] The 2013 frequency response performance values for each interconnection are compared to the IFROs calculated in 2013 for the 2014 operating year to (December 2013 through November 2014).

Eastern Interconnection

NOTE: Frequency response performance data from the Eastern Interconnection in the *State of Reliability 2014* report were reviewed in detail due to outliers that appeared to show a statistically significant decrease of frequency response in 2013 compared to 2011. Nineteen inappropriate frequency events were found to have been included in error.

The analysis below reflects the corrected data, showing steady frequency response performance for the Eastern Interconnection.

Revised statistical analysis of the annual changes in Eastern Interconnection frequency response concluded that there were no other statistically significant changes in the expected frequency response by year for the Eastern Interconnection.

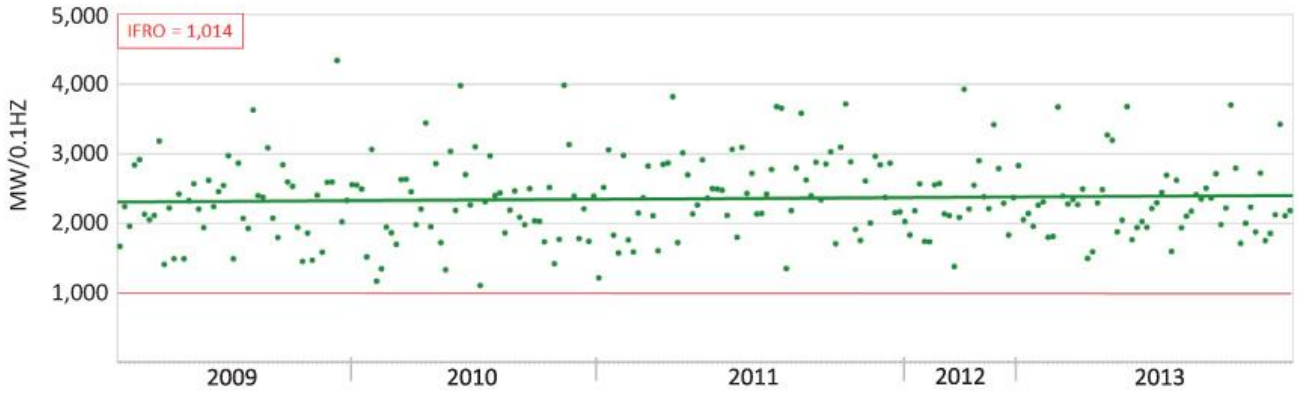


Figure 1: Eastern Interconnection Frequency Response Trend 2009–2013

Table 1: Eastern Interconnection Frequency Response Statistics

Year	Number of Events	MW/0.1 Hz				Number of Events with FR below the |IFRO=1,014[10]|
		Mean of Frequency Response	Std. Dev. of Frequency Response	Min.	Max.	
2009–2013	238	2,349.2	582.3	1,102.5	4,335.9	0
2009	44	2,258.4	522.5	1,404.8	3,625.0	0
2010	49	2,335.7	697.6	1,102.5	4,335.9	0
2011	65	2,467.8	593.7	1,210.0	3,815.2	0
2012	28	2,314.3	523.6	1,374.0	3,921.4	0
2013	52	2,309.2	523.3	1,491.0	3,696.3	0

[9] Located at: http://www.nerc.com/pa/RAPA/ri/Pages/InterconnectionFrequencyResponse.aspx

[10] Based on the *2013 Frequency Response Annual Analysis*.

Western Interconnection

It was not possible to statistically analyze the annual changes in the Western Interconnection frequency response due to the small sample sizes for each year.

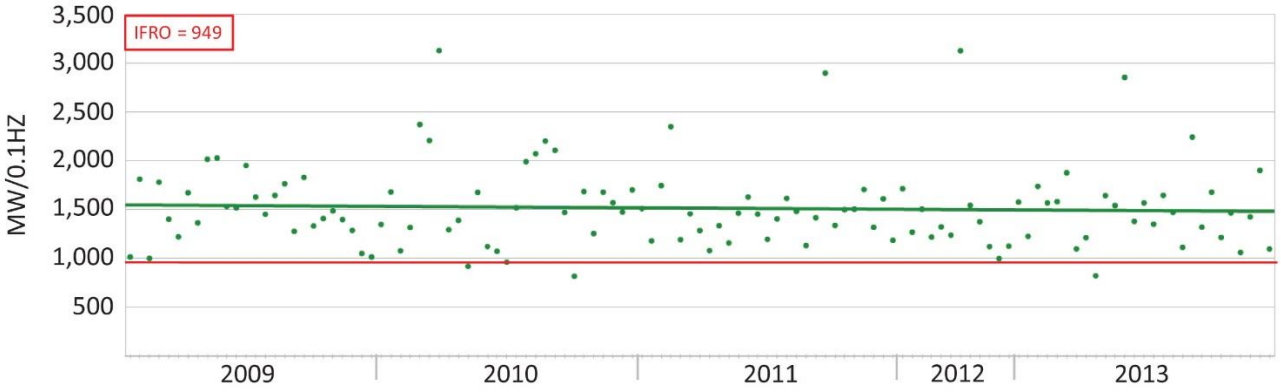


Figure 2: Western Interconnection Frequency Response Trend 2009–2013

Table 2: Western Interconnection Frequency Response Statistics

Year	Number of Events	MW/0.1 Hz				Number of Events with FR below the |IFRO=949[11]|
		Mean of Frequency Response	Std. Dev. of Frequency Response	Min.	Max.	
2009–2013	119	1,514.0	422.9	816.7	3,125.0	3
2009	25	1,513.6	295.7	1,000.0	2,027.0	0
2010	29	1,572.2	512.3	816.7	3,125.0	2
2011	25	1,496.5	391.9	1,078.6	2,894.6	0
2012	12	1,466.8	557.2	997.0	3,123.5	0
2013	28	1,491.2	404.3	821.9	2,851.0	1

[11] Based on the *2013 Frequency Response Annual Analysis*.

ERCOT Interconnection

Statistical analysis of the annual changes in ERCOT Interconnection frequency response found four statistically significant improvements in the expected frequency response (between 2009 and 2013, between 2010 and 2013, between 2011 and 2013, and between 2012 and 2013).

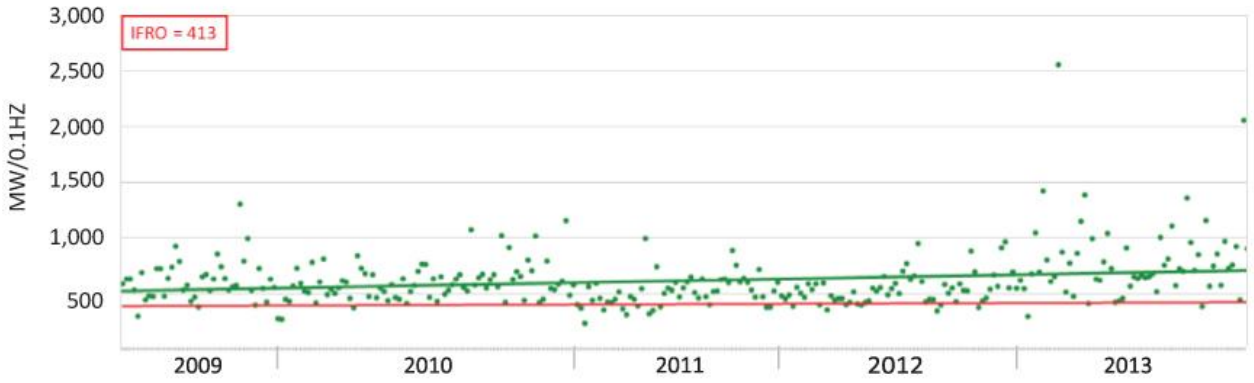


Figure 3: ERCOT Interconnection Frequency Response Analysis for 2009–2013

Table 3: ERCOT Interconnection Frequency Response Statistics						
Year	Number of Events	MW/0.1 Hz				Number of Events with FR below the |IFRO=413[12]|
		Mean of Frequency Response	Std. Dev. of Frequency Response	Min.	Max.	
2009–2013	298	612.2	240.8	228.0	2,552.8	34
2009	51	595.2	185.0	263.5	1,299.1	5
2010	67	609.7	164.8	367.6	1,152.5	3
2011	65	509.6	131.3	228.0	993.0	15
2012	63	571.2	191.9	290.4	1,417.9	9
2013	52	809.8	383.2	378.7	2,552.8	2

Several factors contributed to the frequency response performance improvement in the ERCOT Interconnection in 2012 and 2013.

- During 2013, generators continued to improve their delivery of primary frequency response as they completed process control improvements as a result of the 2012 TRE investigations into primary frequency response performance of generators.
- Approval and implementation of Regional Standard BAL-001-TRE-1 Primary Frequency Response in the ERCOT Region has begun. This regional standard sets specific governor droop and dead-band settings and provides performance measures to assure delivery of primary frequency response from generators. Generators and the Balancing Authority are actively working to meet the implementation deadlines set in this regional standard.

[12] Based on the *2013 Frequency Response Annual Analysis*.

Québec Interconnection

Statistical analysis of the annual changes in the Québec Interconnection frequency response found there are no statistically significant changes in the expected frequency response by year.

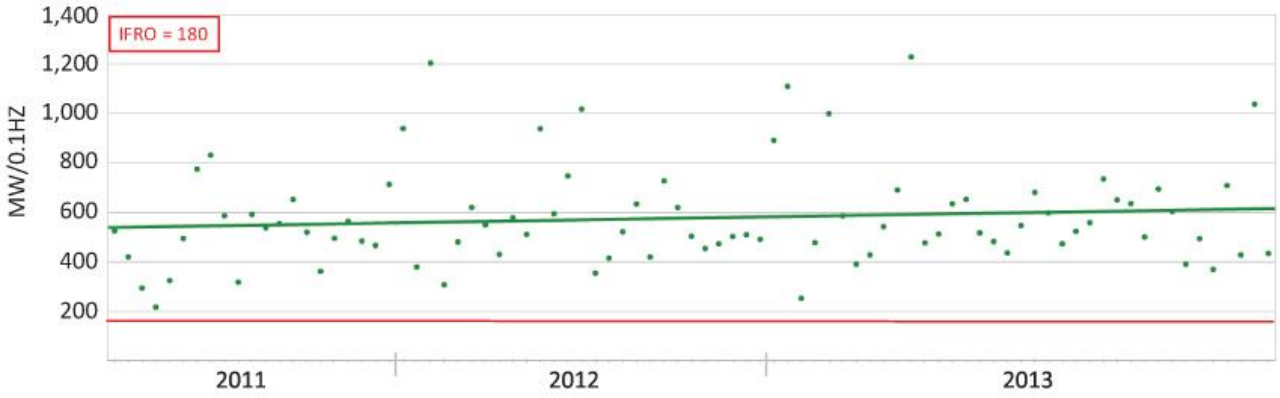


Figure 4: Québec Interconnection Frequency Response Analysis for 2011–2013

Table 4: Québec Interconnection Frequency Response Statistics

Year	Number of Events	MW/0.1 Hz				Number of Events with FR below the |IFRO=180[13]|
		Mean of Frequency Response	Std. Dev. of Frequency Response	Min.	Max.	
2011–2013	85	575.3	202.9	214.7	1,228.0	0
2011	20	499.1	153.6	214.7	829.9	0
2012	28	592.7	212.4	305.9	1,202.1	0
2013	37	603.3	213.3	250.9	1,227.8	0

[13] Based on the *2013 Frequency Response Annual Analysis*.

Interconnection Frequency Characteristic Analysis

Frequency Variation Statistical Analysis

NERC staff annually performs a statistical analysis[14] of the variability of frequency for each of the four interconnections using a three-year window of one-second measured frequency. For this report's analysis, frequency data from 2011–2013 was used and is summarized in Table 5.

This variability accounts for items such as time-error correction; variability of load, interchange, and frequency over the course of a normal day; and other uncertainties, including all frequency events.

Table 5: Interconnection Frequency Variation Analysis

Value	Eastern	Western	ERCOT	Québec
Time Frame	2011-2013	2011-2013	2011-2013	2011-2013
Number[15] of Samples	91,199,012	91,232,854	88,538,959	86,770,408
Expected Value (Hz)	60.000	59.999	59.999	59.994
Variance of Frequency (σ^2) (Hz^2)	0.00024	0.00058	0.00062	0.00584
Standard Deviation (σ) (Hz)	0.01543	0.02399	0.02488	0.07642
2σ (Hz)	0.03086	0.04799	0.04975	0.15283
3σ (Hz)	0.04629	0.07198	0.07463	0.22925
Starting Frequency (F_{Start}) 5% of lower tail samples (Hz)	**59.974**	**59.968**	**59.965**	**59.969**

Those starting frequencies encompass all variations in frequency, including changes to the target frequency during time-error correction (TEC). That eliminates the need to expressly evaluate TEC as a variable in the IFRO calculation. Therefore, the starting frequency for the calculation of IFROs should remain the frequency calculated at 5 percent of the lower tail of samples from the statistical analysis, which represents a 95 percent chance that frequencies will be at or above that value at the start of any frequency event.

Figures 5–8 show the probability density function of frequency for each interconnection.

[14] Refer to the 2012 *Frequency Response Initiative* report for details on the statistical analyses used.

[15] Numbers of samples vary due to exclusion of data drop-outs and other obvious observation anomalies.

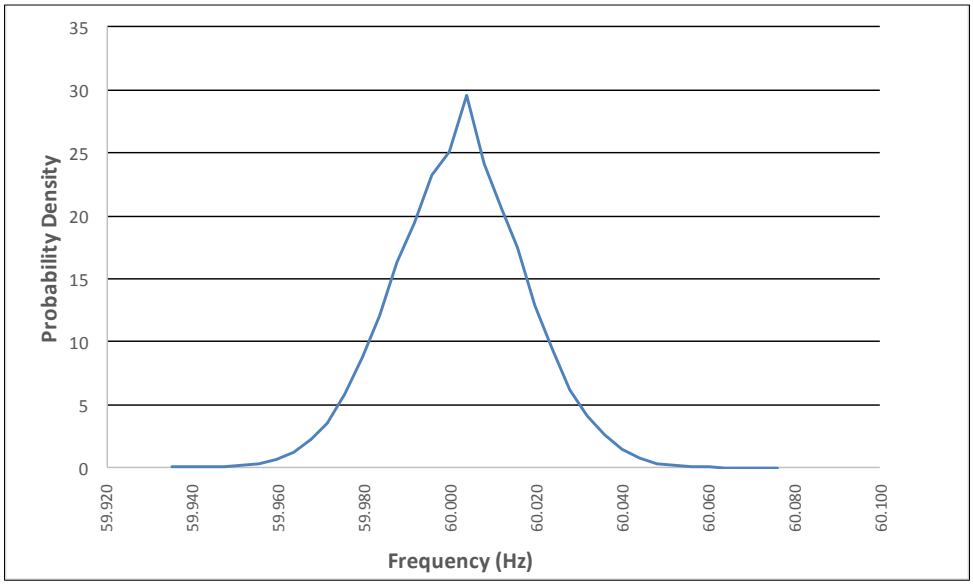


Figure 5: Eastern Interconnection 2011–2013 Probability Density Function of Frequency

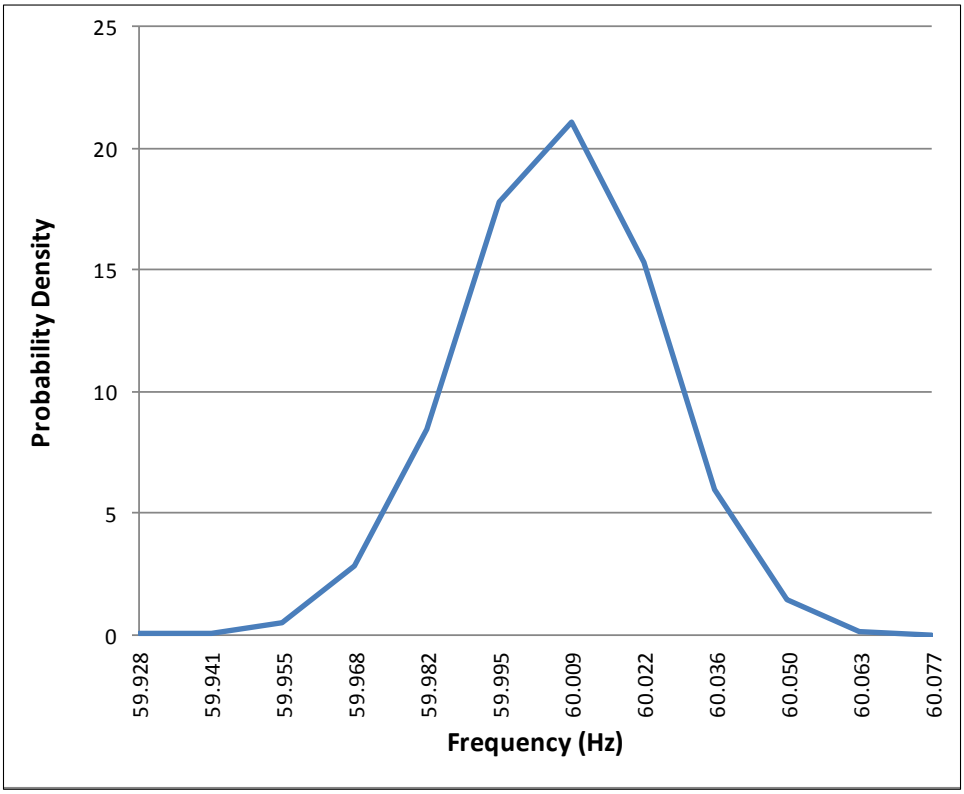


Figure 6: Western Interconnection 2011–2013 Probability Density Function of Frequency

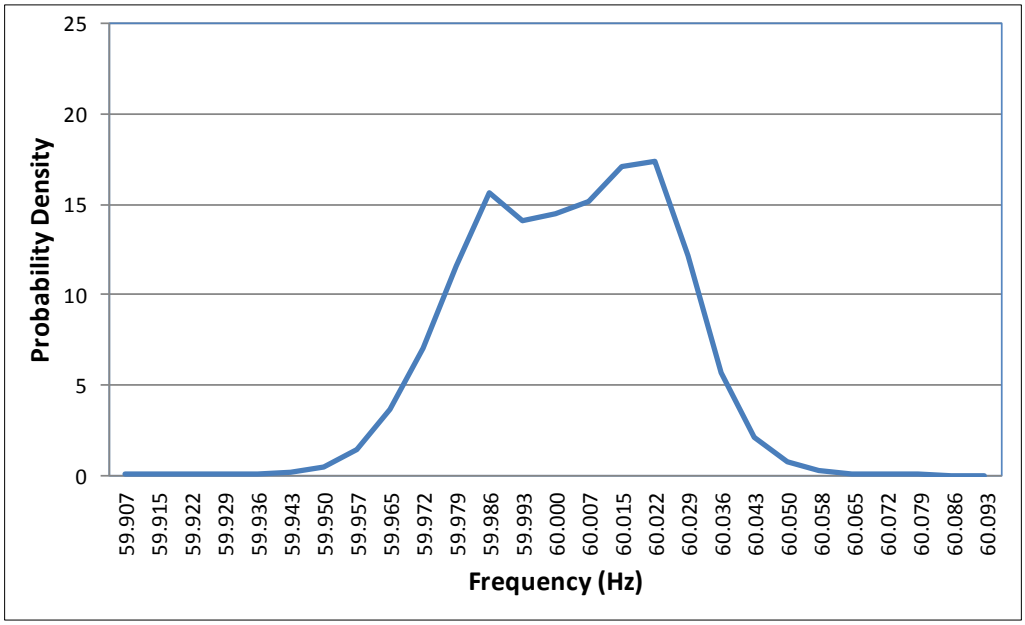


Figure 7: ERCOT Interconnection 2011–2013 Probability Density Function of Frequency

Note that the ERCOT frequency probability density still displays some minor influence of the "flat-top" profile that was common to that interconnection prior to 2008. That phenomenon was caused by a standardized ±36 mHz dead band with a step-function implementation. This is significantly less pronounced than it was in the 2012 analysis as the impacts of migration toward a ±16.7 mHz dead band with a proportional response implementation became more pronounced in the 2011 and 2012 data.

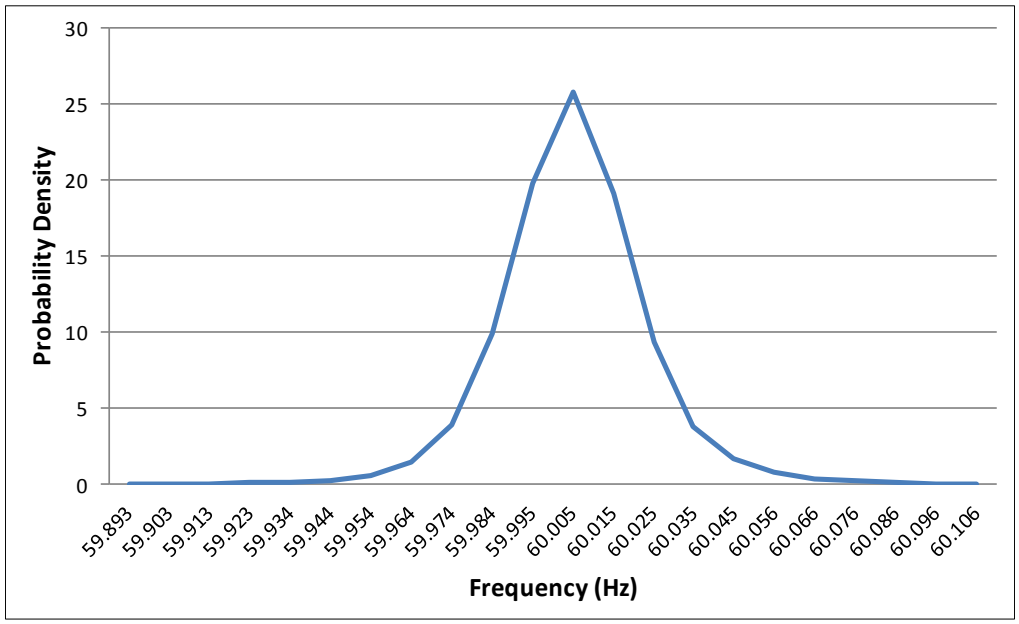


Figure 8: Québec Interconnection 2011–2013 Probability Density Function of Frequency

Changes in Starting Frequency

Comparing the results of the 2014 frequency variability analysis for the 2011–2013 data with those conducted in 2013 (Table 6) shows only slight variations in the starting frequencies.

Table 6: Comparison of Interconnection Frequency Statistics (Hz)			
Expected Frequencies			
	2013 Analysis	2014 Analysis	Change
Eastern	60.000	60.000	–
Western	59.996	59.999	0.003
ERCOT	59.994	59.999	0.005
Québec	59.980	59.994	0.014
Starting Frequencies			
Eastern	59.974	59.974	–
Western	59.971	59.968	-0.003
ERCOT	59.964	59.965	0.001
Québec	59.968	59.969	0.001

Determination of Interconnection Frequency Response Obligations

Tenets of IFRO

The IFRO is the minimum amount of frequency response that must be maintained by an interconnection. Each BA in the interconnection should be allocated a portion of the IFRO that represents its minimum responsibility. To be sustainable, BAs that may be susceptible to islanding may need to carry additional frequency-responsive reserves to coordinate with their underfrequency load shedding (UFLS) plans for islanded operation.

A number of methods to assign the frequency response targets for each interconnection can be considered. Initially, the following tenets should be applied:

1. A frequency event should not trip the first stage of regionally approved UFLS systems within the interconnection.
2. Local tripping of first-stage UFLS systems for severe frequency excursions, particularly those associated with protracted faults or on systems on the edge of an interconnection, may be unavoidable.
3. Other frequency-sensitive loads or electronically coupled resources may trip during such frequency events (as is the case for photovoltaic inverters in the Western Interconnection).
4. It may be necessary in the future to consider other susceptible frequency sensitivities (e.g., electronically coupled load common-mode sensitivities).

UFLS is intended to be a safety net to prevent system collapse from severe contingencies. Conceptually, that safety net should not be violated for frequency events that happen on a relatively regular basis. As such, the resource loss protection criteria were selected through the Frequency Response Initiative 2012 analysis to avoid violating regionally approved UFLS settings.

IFRO Formulae

The following are the formulae that comprise the calculation of the IFROs:

$$DF_{Base} = F_{Start} - UFLS$$

$$DF_{CC} = DF_{Base} - CC_{Adj}$$

$$DF_{CBR} = \frac{DF_{CC}}{CB_R}$$

$$MDF = DF_{CBR} - BC'_{Adj}$$

$$ARLPC = RLPC - CLR$$

$$IFRO = \frac{ARLPC}{MDF}$$

Where:

- DF_{Base} is the base delta frequency.
- F_{Start} is the starting frequency determined by the statistical analysis.
- UFLS is the highest UFLS trip set point for the interconnection.
- CC_{ADJ} is the adjustment for the differences between one-second and sub-second Point C observations for frequency events. A positive value indicates that the sub-second C data is lower than the one-second data.

- DF_{CC} is the delta frequency adjusted for the differences between one-second and sub-second Point C observations for frequency events.
- CB_R is the statistically determined ratio of the Point C to Value B.
- DF_{CBR} is the delta frequency adjusted for the ratio of Point C to Value B.
- BC'_{ADJ} is the statistically determined adjustment for the event nadir occurring below the Value B (Eastern Interconnection only) during primary frequency response withdrawal.
- MDF is the maximum allowable delta frequency.
- RLPC is the resource loss protection criteria.
- CLR is the credit for load resources.
- ARLPC is the adjusted resource loss protection criteria adjusted for the credit for load resources.
- IFRO is the interconnection frequency response obligation.

Determination of Adjustment Factors

Adjustment for Differences between Value B and Point C (CB_R)

All of the calculations of the IFRO are based on avoiding instantaneous or time-delayed tripping of the highest set point (step) of UFLS, either for the initial nadir (Point C), or for any lower frequency that might occur during the frequency event. The frequency variance analysis in the previous section of this report is based on one-second data from January 2011 through May 2014.

As a practical matter, the ability to measure the tie line and loads for the BAs is limited to supervisory control and data acquisition (SCADA) scan-rate data of 1–6 seconds. Therefore, the ability to measure frequency response of the BAs is still limited by the SCADA scan rates available to calculate Value B.

Candidate events from the ALR 1–12 interconnection frequency response selection process for frequency response analysis were used to analyze the relationship between Value B and Point C for the significant frequency disturbances from January 2011 through May 2014. This sample set was selected because data was available for the analysis on a consistent basis. This resulted in the number of events shown in Table 7.

Analysis Method

The IFRO is the minimum performance level that the BAs in an interconnection must meet through their collective frequency response to a change in frequency. This response is also related to the function of the frequency bias setting in the area control error (ACE) equation of the BAs for the longer term. The ACE equation looks at the difference between scheduled frequency and actual frequency, times the frequency bias setting to estimate the amount of megawatts that are being provided by load and generation within the BA. If the actual frequency is equal to the scheduled frequency, the Frequency Bias component of ACE must be zero.

When evaluating some physical systems, the nature of the system and the data resulting from measurements derived from that system do not fit the standard linear regression methods that allow for both a slope and an intercept for the regression line. In those cases, it is better to use a linear regression technique that represents the system correctly.

Since the IFRO is ultimately a projection of how the interconnection is expected to respond to changes in frequency related to a change in megawatts (resource loss or load loss), there should be no expectation of frequency response without an attendant change in megawatts. It is this relationship that indicates the appropriateness of using regression with a forced fit through zero.

Determination of C-to-B Ratio (CB_R)

The evaluation of data to determine the C-to-B ratio (CB_R) to account for the differences between arrested frequency response (to the nadir, Point C) and settled frequency response (Value B) is also based on a physical representation of the electrical system. Evaluation of this system requires investigation of the meaning of an intercept. The CB_R is defined as the difference between the pre-disturbance frequency and the frequency at the maximum deviation in post-disturbance frequency, divided by the difference between the pre-disturbance frequency and the settled post-disturbance frequency.

$$CB_R = \frac{Value\ A - Point\ C}{Value\ A - Value\ B}$$

A stable physical system requires the ratio to be positive; a negative ratio indicates frequency instability or recovery of frequency greater than the initial deviation. The CB_R adjusted for confidence (Table 7) should be used to compensate for the differences between Point C and Value B.

Table 7: Analysis of Value B and Point C (CB_R)

Interconnection	Events Analyzed	Mean	Standard Deviation	CB_R 95% Confidence	CB_R Adjusted for Confidence
Eastern	158	0.954	0.193	0.025	1.000 (0.979)[16]
Western	79	1.607	0.348	0.065	1.672
ERCOT	169	1.548	1.200	0.153	1.700
Québec[17]	N/A	N/A	N/A	N/A	1.550

This statistical analysis was completed using one-second averaged data that does not accurately capture Point C, which is better measured by high-speed metering (phasor measurement units (PMUs) or frequency disturbance recorders (FDRs)). Therefore, a separate correction must be used to account for the differences between the Point C in the one-second data and the Point C values measured with sub-second measurements from the FNet[18] (Frequency Monitoring Network) FDRs.

The CB_R value for the Eastern Interconnection indicates that Value B is generally below the Point C value. Therefore, no adjustment is necessary for that interconnection, and the CB_R value is set to 1.000.

The Québec Interconnection's resources are predominantly hydraulic and are operated to optimize efficiency, typically at about 85 percent of rated output. Consequently, most generators have about 15 percent headroom to supply primary frequency response. This results in a robust response to most frequency events, exhibited by high rebound rates between Point C and the calculated Value B. For the 67 frequency events in their event sample, Québec's CB_R value would be 4.161, or two to four times the CB_R values of other interconnections. Using the same calculation method for CB_R would effectively penalize Québec for their rapid rebound performance and make their IFRO artificially high. Therefore, the method for calculating the Québec CB_R was modified.

[16] CB_R value limited to 1.000 because values lower than that indicate the Value B is lower than Point C and does not need to be adjusted. The calculated value is 0.979.

[17] Based on Québec UFLS design between their 58.5 Hz UFLS with 300 millisecond operating time (responsive to Point C) and 59.0 Hz UFLS step with a 20-second delay (responsive to Value B or beyond) with a 0.05 Hz confidence interval. See the adjustment for differences between Value B and Point C section of this report for further details.

[18] Operated by the Power Information Technology Laboratory at the University of Tennessee, FNet is a low-cost, quickly deployable GPS-synchronized wide-area frequency measurement network. High-dynamic accuracy FDRs are used to measure the frequency, phase angle, and voltage of the power system at ordinary 120 V outlets. The measurement data are continuously transmitted via the Internet to the FNet servers hosted at the University of Tennessee and Virginia Tech.

Québec operates with an operating mandate for frequency responsive reserves to prevent tripping their 58.5 Hz (300 millisecond trip time) first-step UFLS for their largest hazard at all times, effectively protecting against tripping for Point C frequency excursions. Québec also protects against tripping a UFLS step set at 59.0 Hz that has a 20-second time delay, which protects them from any sustained low-frequency Value B and primary-frequency response withdrawals. This results in a Point C to Value B ratio of 1.5. To account for the confidence interval, 0.05 is then added, making the CB_R equal 1.550.

Point C Analysis – One-Second versus Sub-Second Data (CC_{ADJ})

The basic statistical analysis of the frequency events was performed for the differences between Point C and Value B, calculated as a ratio of Point C to Value B, using one-second data for BAL-003 events from January 2011 through May 2014. Although the one-second data sample is robust, it does not necessarily ensure the nadir of the event was accurately captured. To do so requires sub-second measurements that can only be provided by PMUs or FDRs. Therefore, a "C to C" adjustment component (CC_{ADJ}) for the IFRO calculation was designed to account for the differences observed between the one-second Point C and high-speed Point C measurements. The value used is the CC_{ADJ} adjusted for confidence from Table 8.

Table 8: Analysis of One-Second and Sub-Second Data for Point C (CC_{ADJ})

Interconnection	Events Analyzed	Mean (Hz)	Standard Deviation (Hz)	CC_{ADJ} (95% Quantile) (Hz)	CC_{ADJ} Adjusted for Confidence (Hz)[19]
Eastern	158	0.011	0.014	0.032	0.013
Western	78	0.009	0.010	0.018	0.011
ERCOT	154	-0.006	0.050	0.035	0.001
Québec	19	0.026	0.013	0.067	0.031

The CC_{ADJ} should be made to the allowable frequency deviation value before it is adjusted for the ratio of Point C to Value B.

Adjustment for Primary Frequency Response Withdrawal (BC'_{ADJ})

At times, the nadir for a frequency event occurs after Point C—defined in BAL-003-1 as occurring in the T+0 to T+12 second period, during the Value B averaging period (T+20 through T+52 seconds), or later. For purposes of this report, the later-occurring nadir is termed Point C'. This lower nadir is symptomatic of primary frequency response withdrawal, or squelching, by unit-level or plant-level outer-loop control systems. Withdrawal is most prevalent in the Eastern Interconnection.

Primary frequency response withdrawal can become important depending on the type and characteristics of the generators in the resource dispatch, especially during light-load periods. Therefore, an additional adjustment to the maximum allowable delta frequency for calculating the IFROs was statistically developed. This adjustment should be used whenever withdrawal is a prevalent feature of frequency events.

Table 9 shows the number of events for each interconnection where the C' value was lower than Value B (averaged from T+20 through T+52 seconds) for the period of January 2011 through May 2014. A sample of T+300 one-second data was used for this analysis.

[19] Mean value adjusted for a 95 percent confidence interval.

Table 9 shows when Point C' occurred after T+0. For the Western, ERCOT, and Québec Interconnections, the occurrences of Point C' were before or within the Value B time frame, indicating that a Point C' adjustment to Value B is not needed in those interconnections.

Table 9: Seconds from T+0 to C' Nadir				
Interconnection	**Events Analyzed**	**Events W/C' Lower than C**	**Mean Seconds to C'**	**Point C' Time[20] (Confidence Adjusted)**
Eastern	160	146	58	52 s to 65 s
Western	79	2	15	12 s to 19 s
ERCOT	169	33	26	21 s to 31 s
Québec	67	0	12	12 s

Note that the expected time for the Point C' nadir to occur in the Eastern Interconnection is 52 to 65 seconds after the start of the event, which is beyond the Value B time frame. Therefore, a BC'_{ADJ} is only needed for the Eastern Interconnection; no BC'_{ADJ} is needed for the other three interconnections (Table 10).

Table 10: Statistical Analysis of the Adjustment for C' Nadir (BC'_{ADJ})					
Interconnection	**Events Analyzed**	**Events W/C' Lower than B**	**Mean**	**Standard Deviation**	**BC'_{ADJ} (95% Quantile)**
Eastern	160	159	7.3 mHz	5.5 mHz	17.4 mHz
Western	Not Applicable				
ERCOT	Not Applicable				
Québec	Not Applicable				

The 95 percent quantile value is used for the Eastern Interconnection BC'_{ADJ} of 17.4 mHz to account for the statistically expected Point C' value of a frequency event.

Variables in Determination of IFROs

To determine the IFROs, a number of other variables must be taken into consideration.

Low-Frequency Limit

The low-frequency limit to be used for the IFRO calculations should be the highest step in the interconnection for regionally approved UFLS systems.

Table 11: Low-Frequency Limits (Hz)	
Interconnection	**Highest UFLS Trip Frequency**
Eastern	59.5
Western	59.5
ERCOT	59.3
Québec	58.5

[20] Point C' can occur at any time, while Point C is limited to occurrence between T=0 and T=+12 seconds.

Note that the highest UFLS set point in the Eastern Interconnection is 59.7 Hz in FRCC, while the prevalent highest set point in the rest of that interconnection is 59.5 Hz. The FRCC 59.7 Hz first UFLS step is based on internal stability concerns and to prevent the separation of the Florida peninsula from the rest of the interconnection. FRCC concluded that the IFRO starting point of 59.5 Hz for the Eastern Interconnection is acceptable in that it imposes no greater risk of UFLS operation for an interconnection resource loss event than for an internal FRCC event.

Protection against tripping the highest step of UFLS does not ensure that generation that has frequency-sensitive boiler or turbine control systems will not trip. Severe system conditions might drive the frequency and voltage to levels that present a combination of conditions to control systems that may cause some generation to trip. Severe rate-of-change in voltage or frequency, which might actuate volts-per-hertz relays, could also trip some units. Similarly, some combustion turbines may not be able to sustain operation at frequencies below 59.5 Hz.

Also, electronically coupled resources are susceptible to extremes in frequency. Southern California Edison's recent laboratory testing of inverters used on residential and commercial scale photovoltaic (PV) systems revealed a propensity to trip at about 59.4 Hz, which is 200 mHz above the expected 59.2 Hz prescribed in IEEE Standard 1547 for distribution-connected PV systems rated at or below 30 kW (57.0 Hz for larger installations). This could become problematic in the future in areas of high penetration of PV resources.

Credit for Load Resources (CLR)

The ERCOT Interconnection depends on contractually interruptible demand that automatically trips at 59.7 Hz to help arrest frequency declines. A load resource credit of up to 1,400 MW (formerly called Load acting as a Resource, or LaaR) may be included against the resource contingency for the ERCOT Interconnection. The actual amount of CLR available at any given time varies. Therefore, NERC performed a statistical analysis on hourly available CLR for the period of January 2011 through May 2014. That analysis indicated that at least 909 MW of CLR is available 95 percent of the time. Therefore, a CLR adjustment of 909 MW should be applied in the calculation of the ERCOT IFRO instead of the contractual 1,400 MW, handled in the calculation of the IFRO as a reduction to the loss of resources. This is 14 MW higher than the 895 MW adjustment used in the 2013 IFRO calculations.

Determination of Maximum Allowable Delta Frequencies

Because of the measurement limitation of the BA-level frequency response performance using Value B, IFROs must be calculated in "Value B space." Protection from tripping UFLS for the interconnections based on Point C, Value B, or any nadir occurring after point C, within Value B, or after T+52 seconds must be reflected in the maximum allowable delta frequency for IFRO calculations expressed as in terms comparable to Value B.

Table 12 shows the calculation of the maximum allowable delta frequencies for each of the interconnections. All adjustments to the maximum allowable change in frequency are made to include:

- Adjustments for the differences between one-second and sub-second Point C observations for frequency events;
- Adjustments for the differences between Point C and Value B; and
- Adjustments for the event nadir being below Value B (Eastern Interconnection only) due to primary frequency response withdrawal.

Table 12: Determination of Maximum Allowable Delta Frequencies

	Eastern	Western	ERCOT	Québec	Units
Starting Frequency	59.974	59.968	59.965	59.969	Hz
Minimum Frequency Limit	59.500	59.500	59.300	58.500	Hz
Base Delta Frequency	0.474	0.468	0.665	1.469	Hz
CC_{ADJ}[21]	0.013	0.011	0.001	0.031	Hz
Delta Frequency (DF_{CC})	0.461	0.457	0.664	1.438	Hz
CB_R[22]	1.000[23]	1.672	1.700	1.550[24]	Ratio
Delta Frequency (DF_{CBR})[25]	0.461	0.273	0.391	0.928	Hz
BC'_{ADJ}[26]	0.017	N/A	N/A	N/A	Hz
Max. Allowable Delta Frequency	0.444	0.273	0.391	0.928	Hz

[21] Adjustment for the differences between one-second and sub-second Point C observations for frequency events.
[22] Adjustment for the differences between Point C and Value B.
[23] CB_R value for the Eastern Interconnection limited to 1.000 because values lower than that indicate the Value B is lower than Point C and does not need to be adjusted. The calculated value is 0.979.
[24] Based on Québec UFLS design between their 58.5 Hz UFLS with 300 millisecond operating time (responsive to Point C) and 59.0 Hz UFLS step with a 20-second delay (responsive to Value B or beyond).
[25] DF_{CC}/CB_R
[26] Adjustment for the event nadir being below the Value B (Eastern Interconnection only) due to primary frequency response withdrawal.

Comparison of Maximum Allowable Delta Frequencies

The following is a comparison of the 2014 maximum allowable delta frequencies with those presented in the 2013 *Frequency Response Annual Analysis* report.

Table 13a: Maximum Allowable Delta Frequency Comparison				
Eastern	**2013**	**2014**	**Change**	**Units**
Starting Frequency	59.974	59.974	–	Hz
Min. Frequency Limit	59.500	59.500	–	Hz
Base Delta Frequency	0.474	0.474	–	Hz
CC_{ADJ}	0.009	0.013	0.004	Hz
Delta Frequency (DF_{CC})	0.465	0.461	-0.004	Hz
CB_R	1.000	1.000	–	Ratio
Delta Freq. (DF_{CBR})	0.465	0.461	-0.004	Hz
BC'_{ADJ}	0.021	0.017	-0.004	Hz
Max. Allowable Delta Frequency	0.444	0.444	–	Hz
Western	**2013**	**2014**	**Change**	**Units**
Starting Frequency	59.971	59.968	-0.003	Hz
Min. Frequency Limit	59.500	59.500	–	Hz
Base Delta Frequency	0.471	0.468	-0.003	Hz
CC_{ADJ}	0.008	0.011	0.003	Hz
Delta Frequency (DF_{CC})	0.463	0.457	-0.006	Hz
CB_R	1.774	1.672	-0.102	Ratio
Delta Freq. (DF_{CBR})	0.261	0.273	0.012	Hz
BC'_{ADJ}	N/A	N/A	–	Hz
Max. Allowable Delta Frequency	0.261	0.273	0.012	Hz

In the Eastern Interconnection, the 4 mHz increase in CC_{ADJ} is offset by the 4 mHz decrease in BC'_{ADJ}, resulting in no change to the maximum allowable delta frequency.

There is an increase of 12 mHz in the Western Interconnection maximum allowable delta frequency caused by:

- 0.003 Hz decrease in the starting frequency;
- 0.003 Hz increase in the CC_{ADJ}; and
- 0.102 decrease in the CB_R ratio.

These changes are caused by the changes in the interconnection's frequency characteristics and changes to the frequency response performance in the analyzed events.

Table 13b: Maximum Allowable Delta Frequency Comparison				
ERCOT	**2013**	**2014**	**Change**	**Units**
Starting Frequency	59.964	59.965	0.001	Hz
Min. Frequency Limit	59.300	59.300	–	Hz
Base Delta Frequency	0.664	0.665	0.001	Hz
CC_{ADJ}	0.000	0.001	0.001	Hz
Delta Frequency (DF_{CC})	0.664	0.664	–	Hz
CB_R	1.478	1.700	0.222	Ratio
Delta Freq. (DF_{CBR})	0.449	0.391	-0.059	Hz
BC'_{ADJ}	N/A	N/A	–	Hz
Max. Allowable Delta Frequency	0.449	0.391	-0.059	Hz
Québec	**2013**	**2014**	**Change**	**Units**
Starting Frequency	59.968	59.969	0.001	Hz
Min. Frequency Limit	58.500	58.500	–	Hz
Base Delta Frequency	1.468	1.469	1.001	Hz
CC_{ADJ}	0.000	0.031	0.031	Hz
Delta Frequency (DF_{CC})	1.468	1.438	-0.030	Hz
CB_R	1.550	1.550	–	Ratio
Delta Freq. (DF_{CBR})	0.947	0.928	-0.019	Hz
BC'_{ADJ}	N/A	N/A	–	Hz
Max. Allowable Delta Frequency	0.947	0.928	-0.019	Hz

There is a significant reduction of 59 mHz in the ERCOT Interconnection maximum allowable delta frequency caused by:

- 0.001 Hz increase in the starting frequency;
- 0.001 Hz increase in the CC_{ADJ}; and
- 0.222 increase in the CB_R ratio, caused by significant changes to the ERCOT frequency response performance in the analyzed events.

ERCOT has been experiencing a displacement of coal-fired generation by gas-fired combined-cycle units in its dispatch due to lower prices for natural gas. While the combined-cycle units are responsive in the Value B calculation time frame (+20 to +52 seconds), they are slower than the steam units to respond in the arresting power time frame (+0 to +20 seconds). This results in a similar Value B response but a lower Point C nadir, increasing the CB_R ratio. The frequency response performance in 2013–2014 displaces the older performance characteristics.

There is a reduction of 19 mHz in the Québec Interconnection maximum allowable delta frequency resulting from the first-time application of a CC_{ADJ} adjustment (no data was available in previous years).

Recommended IFROs

Table 14 shows the determination of IFROs for operating year 2015 (December 2014 through November 2015) under standard BAL-003-1 based on a resource loss equivalent to the recommended criteria in each interconnection. The maximum allowable delta frequency values have already been modified to include the adjustments for the differences between Value B and Point C (CB_R), the differences in measurement of Point C using one-second and sub-second data (CC_{ADJ}), and the event nadir being below the Value B (BC'_{ADJ}).

Table 14: Recommended IFROs

	Eastern	Western	ERCOT	Québec	Units
Starting Frequency	59.974	59.968	59.965	59.968	Hz
Max. Allowable Delta Frequency	0.444	0.273	0.391	0.927	Hz
Resource Contingency Protection Criteria	4,500	2,626	2,750	1,700	MW
Credit for LR	–	150	909	–	MW
IFRO[27]	**-1,014**	**-906**	**-471**	**-183**	**MW/0.1Hz**
Absolute Value of IFRO	**1,014**	**906**	**471**	**183**	**MW/0.1Hz**
Absolute Value of Current Interconnection Frequency Response Performance[28]	2,309	1,491	810	603	MW/0.1Hz
2015 IFRO as a % of Interconnection Load[29]	0.16	0.58	0.68	0.48	

[27] Refer to the IFRO Formulae section of this report for further details on the calculation.

[28] Based on 2014 Interconnection Frequency Response Performance from Appendix B of the *State of Reliability 2014* report, reflecting corrections to the ALR 1–12 metric events in the Eastern Interconnection. By interconnection:
EI = -2,349 MW / 0.1Hz, WI = -1,514 MW / 0.1Hz, TI = -612 MW / 0.1Hz, and QI = -575 MW/0.1 Hz.

[29] Interconnection projected Total Internal Demands from the *2014 NERC Long-Term Reliability Assessment* (2015 summer demand):
EI = 617,372 MW, WI = 156,423 MW, TI = 69,057 MW, and QI (2014-2015 winter demand) = 38,316 MW.

Comparison to Previous IFRO Values

The IFROs were first calculated and presented in the 2012 *Frequency Response Initiative Report*. Recommendations from that report called for an annual analysis and recalculation of the IFROs. The following is a comparison of the current IFROs and their key component values to those presented in the 2013 *Frequency Response Annual Analysis* report.

Table 15a: Interconnection IFRO Comparison				
Eastern	**2013**	**2014**	**Change**	**Units**
Starting Frequency	59.974	59.974	–	Hz
Max. Allowable Delta Frequency	0.444	0.444	–	Hz
Resource Contingency Protection Criteria	4,500	4,500	–	MW
Credit for LR	–	–	–	MW
Absolute Value of IFRO	1,014	1,014	–	MW/0.1Hz
Western	**2013**	**2014**	**Change**	**Units**
Starting Frequency	59.971	59.968	-0.003	Hz
Max. Allowable Delta Frequency	0.261	0.273	0.012	Hz
Resource Contingency Protection Criteria	2,626	2,626	–	MW
Credit for LR	150	150	–	MW
Absolute Value of IFRO	949	906	-43	MW/0.1Hz

There is no change to the IFRO for the Eastern Interconnection.

There is a 43 MW decrease in the Western Interconnection IFRO caused by the 3 mHz reduction in the Western Interconnection starting frequency; and the 12 mHz increase in the maximum allowable delta frequency attributable to a decrease in the CB_R ratio.[30]

[30] See Tables 12 and 13a for details.

Table 15b: Interconnection IFRO Comparison				
ERCOT	**2013**	**2014**	**Change**	**Units**
Starting Frequency	59.964	59.965	0.001	Hz
Max. Allowable Delta Frequency	0.449	0.391	-0.059	Hz
Resource Contingency Protection Criteria	2,750	2,750	–	MW
Credit for LR	895	909	14	MW
Absolute Value of IFRO	413	471	58	MW/0.1Hz
Québec	**2013**	**2014**	**Change**	**Units**
Starting Frequency	59.968	59.969	–	Hz
Max. Allowable Delta Frequency	0.947	0.928	-0.019	Hz
Resource Contingency Protection Criteria	1,700	1,700	–	MW
Credit for LR	–	–	–	MW
Absolute Value of IFRO	180	183	3	MW/0.1Hz

There is a 58 MW increase in the ERCOT Interconnection IFRO caused by the 59 mHz reduction in the ERCOT Interconnection maximum allowable delta frequency, which is caused by a 15 percent change in the interconnection's CB_R as discussed in the Comparison of Maximum Allowable Delta Frequencies section of this report, and is offset only slightly by the 14 MW increase in the load resources credit, as discussed in the Credit for Load Resources (CLR) section of this report.

There is only a minor change to the Québec Interconnection IFRO caused by the 19 mHz decrease in the maximum allowable delta frequency due to the first-time application of a CC_{ADJ} adjustment (no data was available in previous years).

Dynamics Analysis of Recommended IFROs

Off-peak dynamics analysis was performed for the recommended IFROs for the Eastern, Western, and ERCOT Interconnections to determine if those levels of primary frequency response are adequate to avoid tripping of the first stage of regionally approved UFLS systems in the interconnection. Light-load cases prepared by each of the interconnections were used for the analyses. In each case, the dynamic governor responses were de-tuned until the primary frequency response of the interconnection matched the recommended IFRO value for the prescribed resource loss. In all three simulations, the effects of automatic generation control (AGC), which typically starts to influence frequency response in the 30to 45 second time frame, were not modeled. This causes the modeled withdrawal of primary frequency response to be exaggerated (see Figure 9).

For the Eastern Interconnection, a 2014 light-load case was used for the analysis that reflects models of the actual governors and a best estimate of units participating in response. That case was created by the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG). In the 2013 analysis, a 2013 light-load "generic" dynamics case was used. It was created by replacing the turbine governor models in the case with a generic governor model. A comparison is also shown in Figure 9.

In all three interconnections analyzed, the recommended frequency response maintained frequency above the highest UFLS set point. Figures 9–11 show the results of the dynamics analyses.

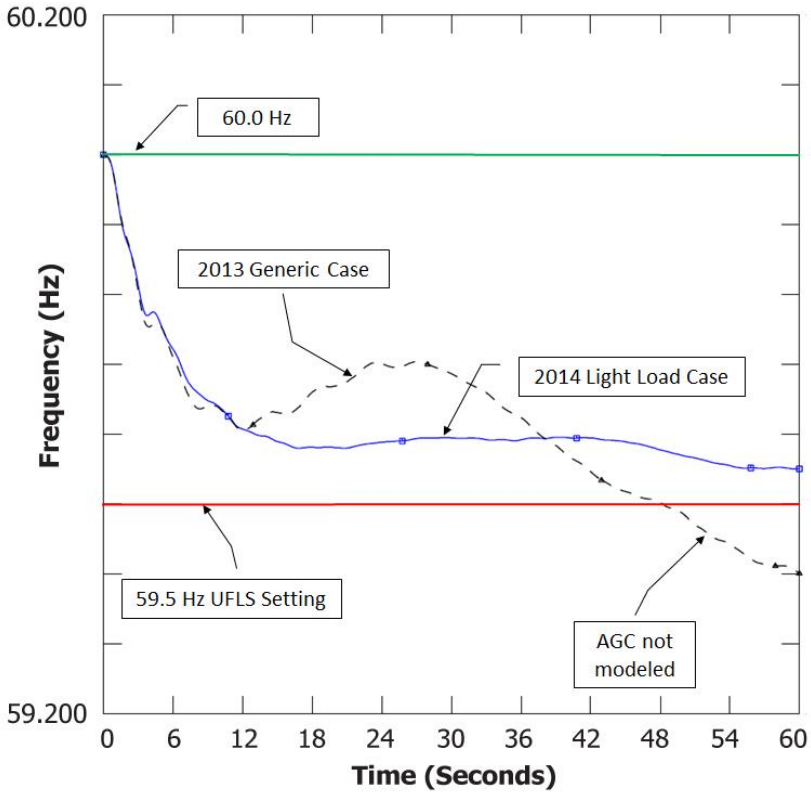


Figure 9: Eastern Interconnection Frequency Response Simulation

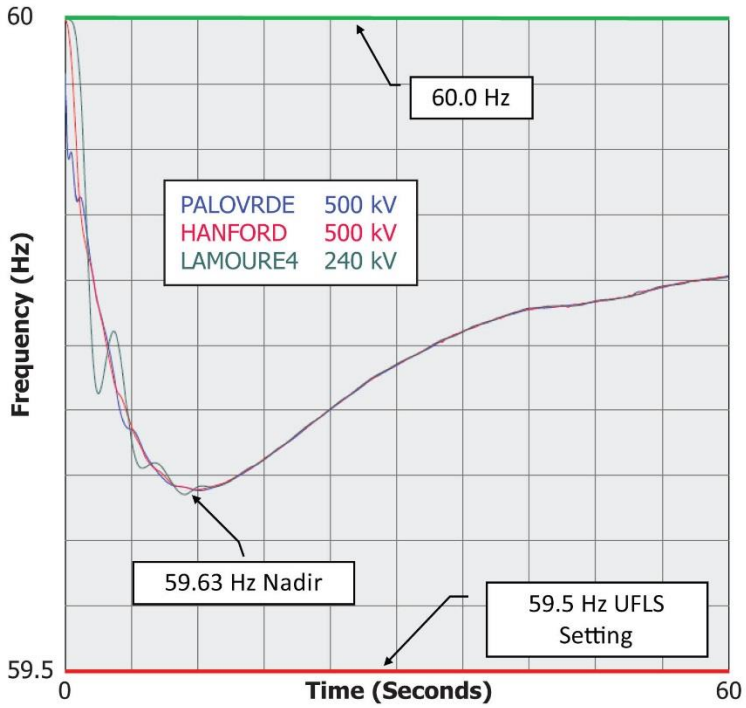


Figure 10: Western Interconnection Frequency Response Simulation

Dynamic simulation of the Western Interconnection 906 MW/0.1 Hz IFRO shows a resulting 59.63 Hz Point C. Similarly, simulation of the ERCOT Interconnection 471 MW/0.1 Hz IFRO shows a resulting 59.39 Hz Point C.

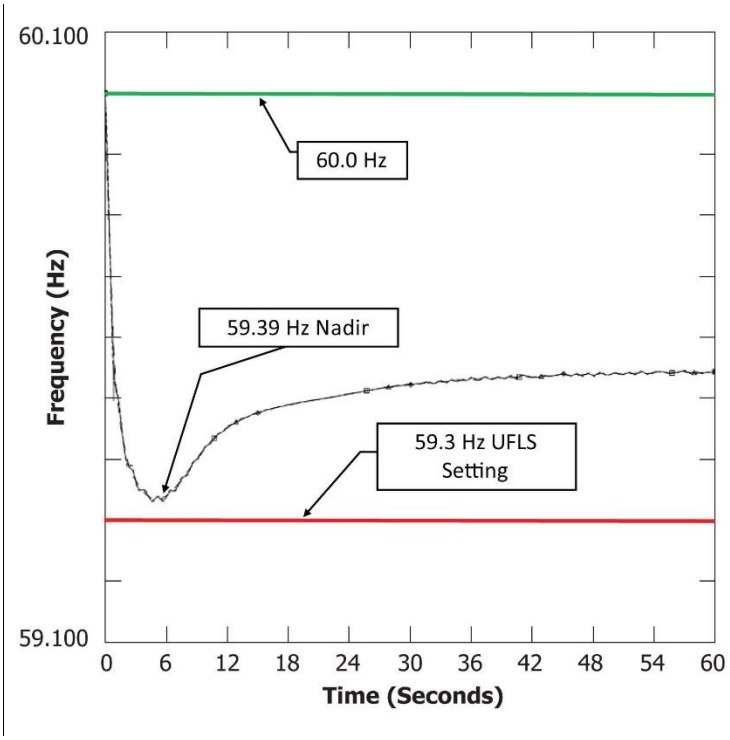


Figure 11: ERCOT Interconnection Frequency Response Simulation

Data Problems and Corrective Action Taken

Several data problems were discovered and corrected during the 2014 analysis of frequency characteristics and frequency response performance.

1. Frequency event selection errors during 2013 were found in the ALR 1–12 Frequency Response metric presented in the *State of Reliability 2014* report. This resulted in 19 Eastern Interconnection events being eliminated from the ALR 1–12 events. The analysis for the Eastern Interconnection is corrected in this report and that correction has been made to the NERC Reliability Indicators dashboard.[31]

2. Frequency step-change[32] anomalies were found in the 2013 one-second Eastern Interconnection frequency data used to determine the starting frequency for the IFRO calculations. The problem was traced back to toggling back and forth between two data sources in the calculation of the one-second averaged data. The entire 2013 one-second database was recalculated to correct the problem.

3. An error was discovered in several start times for frequency events in the Eastern, Western, ERCOT, and Québec Interconnections starting in July 2013.[33] The problem arose from a sign error in an adjustment factor used to remove a time skew inherent in the high-speed metrology; instead of removing the time skew, the adjustment factor was doubling it. This impacted several of the adjustment factors used in the IFRO calculation related to Point C. The error was corrected and all timing of frequency events have been recalculated for this and future analyses.

4. Several sources of sub-second data were determined to be in maintenance/offline mode, which resulted in the provision of inaccurate sub-second frequency data. The sub-second data was corrected by replacing the erroneous sources with data from operational data sources available during frequency events.

Recommendation: NERC staff recommends monthly processing of one-second data and weekly reviewing of the frequency event candidates for both ALR 1–12 and BAL-003-1 so that problems are discovered sooner and consistency in event selection can be ensured.

[31] Located at: http://www.nerc.com/pa/RAPA/ri/Pages/InterconnectionFrequencyResponse.aspx
[32] Abrupt changes in frequency.
[33] This problem did not affect the 2013 IFRO calculations because it began after the time frame used in those calculations.

Recommendations for ALR 1–12 Frequency Event Detection and Selection Process Changes

In examining the frequency event selection process for ALR 1–12, NERC staff found the process to be too restrictive in event selection, potentially skewing the statistical analysis results of frequency response performed for the annual *State of Reliability* report. The Resources Subcommittee and NERC staff recommend that the process for selecting ALR 1–12 events be carefully reviewed and analyzed prior to the publication of the 2015 *State of Reliability* report.

The selection process discounted events that started above 60 Hz and did not fall below certain frequency deviation thresholds. Doing so tends to corrupt any analysis of the statistical relationship between frequency response performance and starting frequency or ending frequency, and potentially eliminates events of high frequency response performance for large events or low frequency response for large MW changes in an interconnection.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RR15-2-000**

MOTION FOR A 45-DAY EXTENSION OF TIME
OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Pursuant to Rules 212 and 2008 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") Rules of Practice and Procedure, 18 C.F.R. §§ 385.212 and 385.2008 (2014), the North American Electric Reliability Corporation ("NERC")[1] hereby requests a 45-day extension of time to file Rules of Procedure changes in accordance with the Commission's February 19, 2015 Order in Docket No. RR15-2-000.[2]

In its February 19 Order, the Commission approved NERC's implementation of the Reliability Assurance Initiative into a risk-based compliance monitoring and enforcement program ("risk-based CMEP")[3] and directed NERC, among other things, to submit, within 90 days, a compliance filing proposing revisions to the NERC Rules of Procedure that describe the fundamental risk-based CMEP concepts and programs.[4] The February 19 Order became

[1] NERC is the Commission-certified electric reliability organization ("ERO") responsible for the development and enforcement of mandatory Reliability Standards. *See North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 342 (D.C. Cir. 2009).

[2] *See North American Electric Reliability Corporation, Order on Electric Reliability Organization Reliability Assurance Initiative and Requiring Compliance Filing*, 150 FERC ¶ 61,108 (2015) ("February 19 Order").

[3] Because of the completion of the Reliability Assurance Initiative at the close of 2014, NERC will reference the ongoing programs as the "risk-based CMEP."

[4] *Id.*, at P 29.

effective upon issuance, requiring NERC to submit the Rules of Procedure changes by May 20, 2015.[5]

As discussed herein, additional time is needed to comply with the Commission directives in its February 19 Order with respect to the Rules of Procedure revisions. This request is consistent with prior FERC action granting motions for extension of time in certain circumstances where the Commission-directed period may be too short to address all required items.[6]

The additional time is necessary to accommodate each of the required steps within the open, collaborative, and participatory process that applies to developing revisions of the NERC Rules of Procedure. The present request, for a 45-day extension of time, does not pose any risk to the reliability of the Bulk-Power System. This request also does not affect the other items that the Commission requested the ERO address in the May 20, 2015 compliance filing. Should the Commission grant this motion, NERC would submit the Rules of Procedure revisions discussed herein on or before July 6, 2015.

I. THE PROCESS FOR REVISING THE NERC RULES OF PROCEDURE

Section 215(f) of the Federal Power Act provides the framework for revisions to the NERC Rules of Procedure. Section 215(f) states that "[t]he Electric Reliability Organization shall file with the Commission for approval any proposed rule or proposed rule change,

[5] Ninety days from February 19, 2015.

[6] *See Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062, P 3 n.2 (2006) ("the Certification Order") (the Commission noting that "90 days may be inadequate to address clarifications or revisions required by the Commission"). *See generally North American Electric Reliability Corporation Notice Granting Extension of Time, Docket* No. RM13-5-000 (January 13, 2015) (granting of a 10-day extension of time to file revisions to the CIP Standards required by Order No. 791); *North American Electric Reliability Corporation Order Granting Extension of Time*, Docket Nos. RM12-6-000 and RM12-7-000 (June 13, 2013) (granting a one year extension for the effective date of the definition of "Bulk Electric System").

accompanied by an explanation of its basis and purpose." The Act goes on to state that the proposed rule or rule change "shall take effect upon a finding by the Commission, after notice and opportunity for comment, that the change is just, reasonable, and not unduly discriminatory or preferential, is in the public interest, and satisfies the requirements of subsection (c) [of §215]." The Commission's regulations at 18 C.F.R. §39.10 echo these requirements and require that the filing include "a description of the proceedings conducted by the Electric Reliability Organization . . . to develop the proposal." The NERC Rules of Procedure are ERO rules as defined in the Commission's regulations at 18 C.F.R. §39.1.

The NERC Bylaws (Article XI, section 2) specify the following process for NERC Rules of Procedure revisions:

> Adoption, Amendment, and Repeal of Rules of Procedure— Except as provided in Section 2 of Article XII, all Rules of Procedure, amendments thereto and repeals thereof shall be approved by the board…Unless the board determines that exigent conditions exist requiring adoption of a new Rule of Procedure or amendment or repeal of an existing Rule of Procedure in a shorter time, *all proposals for adoption, amendment and repeal of Rules of Procedure shall be posted on the Corporation's Web site and subject to public comment for a minimum of forty-five(45) days prior to action by the board*.
>
> [*Emphasis added*.]

The NERC Rule of Procedure §1402, Approval or Amendment or Repeal of the Rules of Procedure, states:[7]

> Amendment to or repeal of Rules of Procedure shall be approved by the Board after public notice and opportunity for comment in accordance with the Bylaws of NERC. *In approving changes to the Rules of Procedure, the Board shall consider the inputs of the Member Representatives Committee, other ERO committees affected by the particular changes to the Rules of Procedure, and other stakeholders as appropriate*. After Board approval, the amendment or repeal shall be submitted to the Applicable Governmental Authorities for approval, where authorized by legislation or agreement. No amendment to or repeal of the Rules of

[7] On May 7, 2012, NERC filed a petition requesting approval of revisions to its Rules of Procedure, which included Section 1400. The Commission approved NERC's proposed revisions to Section 1400. *North American Electric Reliability Corporation Order Conditionally Approving Revisions to North American Electric Reliability Corporation Rules of Procedure*, 141 FERC ¶ 61,241, at P 10 (2012).

> Procedure shall be effective until it has been approved by the Applicable Governmental Authorities.
>
> [*Emphasis added.]*

In addition to the Rules of Procedure and Bylaws, on August 16, 2012, the Board of Trustees approved a NERC staff report on process enhancements and improvements with respect to the development of new or revised NERC Rules of Procedure.[8] These process enhancements include collaborating on the revisions with the Regional Entities and reviewing the proposed revisions with Regional Entity management prior to posting revisions for stakeholder comment.

These process improvements allow for more transparency and opportunity for Regional Entity and other stakeholder participation in the revision process. Under these process enhancements, each posted set of proposed Rules of Procedure revisions requires the drafting of multiple documents to provide a complete record for an informed stakeholder group to consider any proposed changes. The posting also includes a redline version of the Rules of Procedure sections and/or Appendices to which the revisions are proposed. Separate from the redline document, NERC also includes a concise narrative statement of the basis, purpose, and rationale for each proposed revision. Finally, NERC prepares and sends a notice of the proposed revisions advising stakeholders of the posting, providing links or directions to the posting on the NERC website, and identifying the comment due dates.

The process enhancements also require NERC to post the final version of the proposed revisions at least 15 days prior to the date of the Board of Trustees meeting in which the revisions are to be considered. This posting includes a document summarizing the comments received and what action NERC took in response to the comments. In addition to the publicly

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[8] *See* the NERC Board of Trustees Meeting Agenda for August 16, 2012 at p. 44, *available at* http://www.nerc.com/gov/bot/Agenda%20Minutes%20and%20Highlights%20DL/2012/0-BOT08-12a-complete.pdf.

posted document, NERC staff also prepares a matrix for the Board of Trustees that includes a description of the revisions, summaries of the comments received, and NERC's response to those comments.

II. REQUEST FOR A 45-DAY EXTENSION OF TIME

As noted above, NERC requests a 45-day extension of time in order to file Rules of Procedure changes in accordance with the February 19 Order. As described below, good cause exists for this requested extension and proposed schedule modification. First, the additional time will allow for collaboration with Regional Entity and stakeholders. Second, the additional time will not have an impact on addressing other aspects of the February 19 Order or have an impact on the Bulk-Power System.

A. Collaboration during the Revision Process

As explained above, NERC's Rules of Procedure revision process includes several opportunities, through public comment periods, for stakeholder comments, insight, and technical feedback. This feedback process is consistent with the participatory and collaborative nature of the ERO and ensures the development of the best possible Rules of Procedure. However, the time allocated to the various steps limits how quickly NERC can file meaningful modifications to the Rules of Procedure with the Commission.

There may be value in the speedy revision of the NERC Rules of Procedure to incorporate the fundamental risk-based CMEP concepts and program, as those concepts and program are already in place throughout the ERO Enterprise. Nevertheless, there is likely more value to be gained from making those revisions within the established time allowances of NERC's existing rules and processes that promote adequate Regional Entity participation and consideration of other stakeholder feedback. Furthermore, in the absence of a compelling reason

for an accelerated timeline, allowing time for the full NERC Rules of Procedure revision process would provide an opportunity for public comment that may identify potential areas of concern that NERC could address prior to a FERC filing, thereby improving the overall document and the efficiency of the notice and comment process.

Granting NERC's motion for a 45-day extension of the Rules of Procedure revision filing deadline would allow for collaboration, identification of potential issues, and a thorough review of any received stakeholder comments, which would in turn increase the efficiency of the notice and comment process associated with the Commission's review of the proposed revisions.

The Reliability Assurance Initiative was a collaborative effort among NERC, the Regional Entities, and industry to identify and implement changes to enhance the effectiveness of compliance monitoring and enforcement. NERC's request for an extension of time ensures the continuation of the collaborative model and recognizes that Regional Entity and industry participants typically have valuable first-hand experience in implementing the activities to be included in the Rules of Procedure.

As noted above, because these Rules of Procedure revisions affect the obligations of the Regional Entities under the Regional Entity Delegation Agreements, NERC procedures require that NERC staff review the proposed revisions with Regional Entity management prior to posting for public comment. NERC staff and Regional Entity management would continue to consult throughout the process and in response to comments. The 90-day timeline provides too limited a period to ensure a meaningful collaboration with the Regional Entities on the Rules of Procedure revisions. Immediately after the Commission issued the February 19 Order, NERC began outreach to the Regional Entities to address the items FERC identified as requiring additional attention. The ERO Enterprise is currently coordinating and collaborating on a draft set of Rules of Procedure redlines complying with the February 19 Order.

In addition to the value of Regional Entity collaboration, NERC appreciates and relies upon strong industry participation and recognizes that it is essential to the development and implementation of its programs, especially when revising its Rules of Procedure. The process detailed above improves the quality of revisions by taking advantage of industry expertise. NERC considers stakeholder comments in its revision process, then prepares and publicly posts a written response to each comment submitted. Stakeholder comments become part of the formal record that is submitted when seeking regulatory and governmental approval of the Rules of Procedure revisions. Comments offer concrete suggestions for improvement, including possible language and supporting rationale.

For these processes to work as intended, i.e. produce a superior work product, the Regional Entities must have the opportunity to collaborate on the revisions and effective stakeholder interest groups must have access and the opportunity to provide feedback to NERC.

B. No Impact to Addressing February 19 Order or Reliability

In addition to providing the opportunity for collaboration, the 45-day extension of time would pose no risk to the reliability of the Bulk-Power System or impede NERC's efforts to address the other matters in the February 19 Order. As a result, the present circumstances do not provide a compelling basis for an accelerated timeline. However, allowing time for the NERC Rules of Procedure revision process would provide an opportunity for public comment that may identify potential areas of concern that NERC could address prior to a FERC filing, thereby improving the overall document and the efficiency of the overall process.

III. PROPOSED TIMELINE AND RELATED MILESTONES

The timeline below illustrates the major milestones and timeframes if the Commission grants the requested 45-day extension.[9]

Post Rules of Procedure revisions for 45-day public comment	**March 30, 2015**
Public comment period closes	May 14, 2015
Prepare summary and responses to all comments received	May 21, 2015
Incorporate comments and prepare final redline document if changes are made	June 1, 2015
Post final Rules of Procedure changes to NERC website	**June 5, 2015**
Special session Board of Trustees Meeting	On or before June 22, 2015
File Rules of Procedure revisions at FERC	**On or before July 6, 2015**

On or before May 20, 2015, NERC will submit a compliance filing to FERC that will address the other areas the Commission identified in its February 19 Order. While this filing would not include the final redline Rules of Procedure changes for FERC approval, it would include a status update regarding the proposed revisions. The inclusion of this overview in the compliance filing is intended to reassure the Commission of NERC's timely work in developing Rules of Procedure revisions consistent with the collaborative nature of NERC's revision process.

[9] "[I]f NERC requests an extension of time, it must also provide the Commission with a proposed timetable for achieving compliance with those specific elements for which it seeks an extension." *Supra* n.6.

IV. CONCLUSION

WHEREFORE, in consideration of the foregoing, NERC respectfully requests that the Commission grant an extension of time as set forth herein.

Respectfully submitted,

/s/ Sonia C. Mendonca

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Counsel for the North American Electric Reliability Corporation

Date: March 12, 2015

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding. Dated at Washington, D.C. this 12th day of March 2015.

/s/ Leigh Anne Faugust
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March 6, 2015

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: North American Electric Reliability Corporation
Docket No. RR15-___-000
Request for Approval of Revisions to NERC's Working Capital and Operating Reserve Policy

Dear Ms. Bose:

The North American Electric Reliability Corporation (NERC) hereby submits the "Request of the North American Electric Reliability Corporation for Approval of Revisions to its Working Capital and Operating Reserve Policy."

NERC's filing consists of: (1) this transmittal letter, (2) the narrative text of this filing, which follows this transmittal letter, and (3) Attachments 1 and 2, all of which are being transmitted in a single pdf file. The Table of Contents to the narrative text lists the 2 attachments.

Please contact the undersigned if you have any questions concerning this filing.

Respectfully submitted,

/s/ Owen E. MacBride
Owen E. MacBride

Attorney for North American Electric Reliability Corporation

UNITED STATES OF AMERICA
Before the
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	)))	**Docket No. RR15-__-000**

REQUEST OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF REVISIONS TO ITS WORKING CAPITAL AND OPERATING RESERVE POLICY

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March 6, 2015

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ATTACHMENTS

Attachment 1: Revised Working Capital and Operating Reserve Policy – Clean version.

Attachment 2: Revised Working Capital and Operating Reserve Policy – Redlined version

I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC") requests the Commission's approval of proposed revisions to NERC's Working Capital and Operating Reserve ("WCOR") Policy. Pursuant to paragraph 7(d) of the Settlement Agreement in Docket No. FA11-21-000 ("Paragraph 7(d)"), NERC is required to file for Commission review and approval certain revisions to its WCOR Policy.[1] The proposed revisions to the WCOR Policy fall within the scope of Paragraph 7(d); accordingly, NERC is submitting the revised WCOR Policy to the Commission for review and approval. In addition, NERC requests approval pursuant to §1107.4 of the NERC Rules of Procedure ("ROP") for a provision of the new Assessment Stabilization Reserve component of the revised WCOR Policy

As explained herein, the principal proposed revisions to the WCOR Policy are:

- Revision to the description of Working Capital to eliminate cash balances necessary to satisfy future obligations under any covenant, financial or other obligation to which NERC is a party as a component of Working Capital; this item will now be a category of Operating Reserve, identified as the Future Obligation Reserve.
- Further classify Operating Reserve into five distinct categories, each with its own stated purpose and use (most of the categories are already reflected in the current WCOR Policy).
- Elimination, as unnecessary, of the "known contingency" component of Operating Reserve, resulting in Operating Reserve having a single Operating Contingency Reserve category, rather than both known and unforeseen contingency categories.
- Establishment of an Assessment Stabilization Reserve as a category of Operating Reserves, to be used in future periods to mitigate wide year-to-year variations in NERC's assessments to load-serving entities ("LSEs").
- Establishment of upper and lower guideline limits to the budgeted amount of the Operating Contingency Reserve.
- Revisions to the Guidelines and Authorities Applicable to Expenditures of Working Capital and Operating Reserves, including increasing the levels of expenditures from

[1] *See North American Electric Reliability Corporation*, 142 FERC ¶61,042 (2013). Paragraph 7(d) refers to the terms "working capital reserves," "operating reserves," "known contingencies," and "unforeseen contingencies" in the WCOR Policy, and states: "NERC will file proposed revisions to the Reserve Policy that would alter any of those definitions, or would change the Reserve Policy's requirement that all excess funds be added to the unforeseen contingency operating reserves and expended in accordance with the Policy's unforeseen contingency guidelines, for Commission review and approval."

Operating Reserves that may be approved by, respectively, the NERC president and chief executive officer ("CEO"), the Finance and Audit Committee of the NERC Board of Trustees ("Board"), and the Board.

- Revisions to the Guidelines and Authorities Required to Reallocate Budgeted Expenditures on an Intra-Year Basis, including authorizing the president and CEO to reallocate budgeted funding to meet an unanticipated resource need, so long as funding is available from budget underruns in other areas and NERC's overall approved budget for the year is not exceeded. Variations in expenditures compared to the budget will continue to be routinely and transparently reported.

- Elimination of the provision regarding addition of unbudgeted full-time equivalent employees ("FTE") or headcount additions, as it is an unnecessary element of the WCOR Policy and a subject that is separately subject to oversight by the NERC Board and Board committees.

Certain provisions of the new Assessment Stabilization Reserve category of Operating Reserve in the WCOR Policy, regarding the use of penalty collections to mitigate year-to-year assessment volatility, represent a departure from the provision of §1107.2 of the NERC ROP that penalty monies received prior to July 1 of a year are to be used as a general offset to NERC's budget for the subsequent fiscal year. Accordingly, as discussed in §III.A.2 below, NERC requests approval of this provision of the revised WCOR Policy, pursuant to §1107.4 of the ROP, as an exception to §1107.2 of the ROP.

NERC wishes to be completely clear that it is not an objective of this filing to propose or to obtain Commission approval of specific amounts of funding of Working Capital or the five categories of Operating Reserve set forth in the revised WCOR Policy, nor to propose or obtain Commission approval for specific expenditures from the reserve accounts. Specific budgeting of funds for Working Capital and the various reserves categories will be the subject of NERC's business plan and budget process for each year, which culminates each year in approval of the proposed business plan and budget by the NERC Board and by the Commission. Similarly, specific expenditures of funds from a Working Capital or Operating Reserve category that are planned as part of the business plan and budget for a particular year will be subject to NERC Board and Commission approval as part of the business plan and budget approval process for

that year. Additionally, specific expenditures of funds from a Working Capital or Operating Reserve category that are needed during the course of a year will be implemented in accordance with the terms of the WCOR Policy applicable to each category, will be reported through the reporting mechanisms described in this filing, and will be approved in accordance with the delegations of authority set forth in the WCOR Policy, including by the Finance and Audit Committee of the NERC Board or by the Board itself, where required, in accordance with the requirements of the WCOR Policy. Further, as required by Paragraph 7(b)(ii) of the Settlement Agreement in Docket No. FA11-21-000 ("Paragraph 7(b)(ii)"), NERC will make a filing with the Commission for review and approval if any amount allocated from the Operating Contingency Reserve plus any amount redirected from previously budgeted funds is, in the aggregate, $500,000 or more for any one specific project or major activity in a program area.

Attachment 1 to this filing is a clean version of the revised WCOR Policy. **Attachment 2** is a redlined version of the WCOR Policy, marked to show the proposed revisions to the version of the WCOR Policy last submitted to the Commission.[2]

NERC respectfully requests that the Commission issue an order approving the revised WCOR Policy on or before May 21, 2015 (the scheduled date of the Commission's public meeting for May). Approval by this date will enable NERC to incorporate the provisions of the revised WCOR Policy into the development of its 2016 Business Plan and Budget. Although the

[2] The original version of the NERC WCOR Policy was provided in Exhibit C to NERC's 2013 Business Plan and Budget filed in Docket No. RR12-13-000. An Amended WCOR Policy was provided as Attachment 1 to NERC's November 22, 2013 compliance filing to the Commission's order on NERC's 2014 Business Plan and Budget filing in Docket No. RR13-9-000. *Compliance Filing of the North American Electric Reliability Corporation in Response to Paragraph 23 of November 1, 2013 Commission Order*, filed November 22, 2013 in Docket No. 13-9-001. The Commission accepted the November 22, 2013 compliance filing in a letter order issued January 3, 2014 in Docket No. RR13-9-001. In its 2015 Business Plan and Budget Filing, NERC stated that it would add a reserve for the Cybersecurity Risk Information Sharing Program ("CRISP") to Operating Reserves in recognition of certain contingencies associated with CRISP. *See Request of the North American Electric Reliability Corporation for Acceptance of its 2015 Business Plan and Budget and the 2015 Business Plans and Budgets of Regional Entities and for Approval of Proposed Assessments to Fund Budgets*, filed August 22, 2014 in Docket No. RR14-6-000 ("2015 Business Plan and Budget Filing"), at 75 and Attachment 2 (NERC 2015 Business Plan and Budget) at 132 (Exhibit E).

2016 Business Plan and Budget is not required to be filed with the Commission for approval until August 24, 2015,[3] NERC will be posting drafts of its 2016 Business Plan and Budget for stakeholder review and comment beginning in late May 2015.

II. NOTICES AND COMMUNICATIONS

Notices and communications concerning this filing may be addressed to:

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III. REVISIONS TO THE NERC WORKING CAPITAL AND OPERATING RESERVE POLICY

There are four principal components to the proposed revisions to the WCOR Policy: (1) revisions to the components or categories of Working Capital and Operating Reserves to eliminate those that have proved to be unnecessary or not useful and to add or specify new categories appropriate to NERC's current programs and operations;[4] (2) establishment of guideline upper and lower limits to the amount of Operating Contingency Reserve to be budgeted each year, based on percentages of NERC's total budget for expenses and fixed assets (these limits to do not apply to other, specific and distinct categories of Operating Reserves established in the WCOR Policy); (3) revisions to the Guidelines and Authorities Applicable to

[3] 18 C.F.R. §39.4(b).

[4] The WCOR Policy is also being revised to state expressly that the Working Capital and Operating Reserve requirements shall be set forth separately in NERC's business plan and budget, which has been NERC's practice.

Expenditures of Working Capital and Operating Reserves; and (4) revisions to the Guidelines and Authorities Required to Reallocate Budgeted Expenditures on an Intra-Year Basis.

A. Revisions to the Components or Categories of Working Capital and Operating Reserve

1. Working Capital

The description of Working Capital in the WCOR Policy is being revised to remove "cash balances reasonably necessary to meet current and future obligations under any covenant, financial, or other obligation to which the company is a party," and make it a separate category of Operating Reserves, identified as the Future Obligation Reserve. This component is being removed from the definition of Working Capital because funds to satisfy future contractual or covenant obligations are not needed to satisfy daily cash flow requirements (which is the customary objective of the provision of Working Capital) and are more appropriately classified as a reserve. Under the revised WCOR Policy, "Working Capital" will consist only of funds needed to satisfy daily cash flow requirements throughout the year, while Operating Reserve will consist of reserves needed to support operations, including contractual and covenant obligations as well as contingencies.

The description of Working Capital is also being revised to state the factors that will be considered in determining the budgeted amount of Working Capital, as well as to acknowledge that NERC will also maintain a line of credit, which is consistent with current and past practice. With this revision and the revision described in the preceding paragraph, the description of Working Capital in the revised WCOR Policy is as follows:

> **Working Capital** represents the amount of funds necessary to satisfy the company's projected cash flow needs during the budget year, taking into account the projected timing of the receipt of funding and timing of capital and operating expenses. In addition to the foregoing, the company shall also maintain a line of credit, with a financial institution, in such amount and upon such terms and conditions, approved by the company's Finance and Audit Committee and the NERC Board of Trustees ("Board").

2. Operating Reserve

The description of Operating Reserve in the WCOR Policy is being revised to eliminate one current component of Operating Reserves and further break down Operating Reserves into five separate categories: Future Obligation Reserve, System Operator Certification Reserve, CRISP Reserve, Operating Contingency Reserve, and Assessment Stabilization Reserve. The first four of these categories are reflected in the current WCOR Policy; the last category is new.

Future Obligation Reserve represents reserves formerly included in Working Capital (as described above), and is described in the revised WCOR Policy as: "funding that has been received to satisfy future obligations under any lease, credit, loan or other agreement to which the company is a party." The revised WCOR Policy gives examples of amounts to be held in Future Obligation Reserve: (i) office lease funding that is in excess of actual office rent expense due to a landlord's partial abatement of rent and a budgeted lease expense based on the straight line amortization of rent expense over the term of the lease; and (ii) reserves or sinking funds requirements to meet covenant or other obligations under loan or other credit agreements. The revised Policy, like the current Policy, also specifies that these reserves shall be available to satisfy any coverage or liquidity requirements under the terms of any loan or credit agreement to which NERC is a party. Funds in the Future Obligation Reserve are to be segregated to ensure they are available for use in satisfying the future obligations.

System Operator Certification Reserve is an existing reserve that supports the System Operator Certification Program Area. The funds in this reserve are generated from the operations of the System Operator Certification Program (*i.e.*, from system operator certification and testing fees that are above incurred expenses) and are used solely to support the needs of operator testing and certification needs of that program, as determined by NERC and the Personnel Certification Governance Committee ("PCGC").

The CRISP Reserve was established as part of NERC's implementation of CRISP and is

used solely to support CRISP.[5] Amounts in the CRISP Reserve have to date been funded solely by third party industry participants in the program. The CRISP Reserve is held in a separate bank account. Addition of a CRISP component to Operating Reserve was described in the 2015 Business Plan and Budget Filing.[6]

The current "known contingency reserve" component of Operating Reserve is being eliminated. The current WCOR Policy provides for a known contingency reserve and an unforeseen contingency reserve. Having two contingency reserves is confusing (*i.e.*, requiring a determination as to whether a particular contingency and amount are "known" or "unforeseen") and unnecessary. With the elimination of the known contingency reserve component, the Operating Reserve will have one general contingency reserve, captioned the Operating Contingency Reserve, consisting of "reserves for contingencies that were not anticipated, assumed to be likely or the timing of which was uncertain, at the time of preparation of the company's business plan and budget."[7] The revised WCOR Policy provides that the determination of the Operating Contingency Reserve will take into consideration projected costs and risks of ongoing operations, projected resource requirements associated with significant ongoing or emerging reliability initiatives, capital spending forecasts, and other factors that the NERC Board, Finance and Audit Committee, and management consider appropriate.

Finally, the Assessment Stabilization Reserve is a new category being added to the WCOR Policy. This category is comprised of funds that may be periodically set aside and

[5] The CRISP and NERC's participation in it were described in detail in NERC's 2015 Business Plan and Budget Filing, at 7-8 and 61-63, and Attachment 2 (NERC 2015 Business Plan and Budget) at xviii, 55-56 and 133-141 (Exhibit F). As described in that filing, funding for the CRISP is provided primarily by third-party industry participants.

[6] *See* 2015 Business Plan and Budget Filing at 75 and Attachment 2 at 132.

[7] The revised WICOR Policy states examples of unforeseen contingencies: "supplemental resources required to assist in the evaluation of significant unforeseen events affecting the Bulk-Power System or to address regulatory directives not final at the time of budgeting."

released in future periods to mitigate significant year-to-year variations in assessments.[8] The objective of the Assessment Stabilization Reserve is to have changes in annual assessments track, within a reasonable band, changes in NERC's total annual budget, with the total budget reflecting prudent fiscal discipline and good stewardship of resources.[9] The revised WCOR Policy provides that funds from this reserve category will be used when available to mitigate year-to-year swings in assessments, which can result from a variety of factors, such as application of penalty funds collected (which can and do vary widely from year to year), surplus funds available from a prior period, a need to replenish the Operating Contingency Reserve, or significant but relatively short-term operating or capital spending needs.

The revised WCOR Policy provides that the amount of the Assessment Stabilization Reserve which is budgeted in any given year will be determined based on a review of the three-year rolling forecast of assessments, as well as the availability of surplus funds and penalty funds to fund the Assessment Stabilization Reserve. The revised WCOR Policy further specifies that, except as otherwise approved by the NERC Board, funds in the Assessment Stabilization Reserve may not be used for any purpose inconsistent with the goal of this reserve category as set forth in the Policy. The proviso "except as otherwise approved by the NERC Board" provides additional flexibility for the Board to approve uses of the Assessment Stabilization Reserve in extreme and highly unusual circumstances, such as an unexpected and significant litigation expense in a particular year or a significant Bulk Power System event or events in a particular year which requires extraordinary investigation expenses. In such a case, it is

[8] Background information regarding factors influencing change in assessments and historic assessment changes is included in the materials presented at the August 2014 and February 2015 meetings of the NERC Finance and Audit Committee (*see* the agenda packages for those meetings, available at: http://www.nerc.com/gov/bot/FINANCE/Pages/2013FinanceandAuditCommittee.aspx).

[9] Prudent fiscal discipline and good stewardship of resources is, or course, a primary objective of all of NERC's budgeting and expenditure decisions. However, in establishing the objectives, terms and uses of the Assessment Stabilization Reserve, NERC management believed it important to highlight that the objective of the Assessment Stabilization Reserve is to mitigate year-to-year fluctuations in assessments that result from such things as year-to-year changes in penalty payments received or the need for unusual, one-time expenditures in a particular year's budget.

anticipated that other available reserves (specifically the Operating Contingency Reserve) would have been exhausted or already drawn down to unacceptably low levels. It is also anticipated that the Board would weigh releasing funds from the Assessment Stabilization Reserve versus using other sources of funds such as drawing down NERC's line of credit. Any such proposed use of this reserve category would be identified in Finance and Audit Committee agenda and discussed in a public meeting of that Committee, and would also be identified on the Board's agenda for approval and discussed and acted upon at an open Board meeting.[10] The use of the Assessment Stabilization Reserve would also be identified in the quarterly budget variance reports that are posted on the NERC website and provided to the Commission.[11]

Additionally, any injection of funds into the Assessment Stabilization Reserve (from penalty collections or other sources), or withdrawal of funds from the Assessment Stabilization Reserve, that is included in the development of the NERC business plan and budget for a year, will be disclosed in posted drafts of the business plan and budget, subject to stakeholder review and comment, and subject to approval by the NERC Board and, ultimately, by the Commission as part of its approval of that year's business plan and budget. Each annual business plan and budget that is filed with the Commission for approval, beginning with the 2016 Business Plan and Budget, will contain a specific proposal, with justification, for the amounts (if any) to be injected into and withdrawn from the Assessment Stabilization Reserve for that year.[12]

NERC has experienced significant year-to-year variations in assessments. For example,

[10] An exception could be if the need for funding related to a confidential matter such as funding for litigation or for an investigation of a specific Bulk Power System event or actions by a particular Registered Entity.

[11] As specified in Paragraph 7(b)(i) of the Settlement Agreement approved in Docket No. FA11-21-000, NERC files with the Commission, within 45 days after the end of each quarter, the unaudited report of NERC's budget-to-actual spending variances during the preceding quarter, including information regarding sources and uses of operating and working capital reserves.

[12] In addition to explaining, in the annual business plan and budget, any proposed injections into or withdrawals from the Assessment Stabilization Reserve in the budget year, NERC plans to include in its annual business plans and budgets two- or three-year forecasts of activity in the Assessment Stabilization Reserve and the impact on projected annual assessments for the forecast period.

for the 2011 through 2015 budgets, assessments increased on average by 8.7% per year from the previous year's budget, but the changes in assessments from year to year ranged from a low of a decrease of 6.0% to a high of an increase of 23.2%. One significant source of year-to-year volatility in NERC's assessments has been year-to-year variations in penalty monies collected by NERC, which have been used to reduce the following year's assessments. The year-to-year variability in assessment levels and the need to do something to mitigate it has been a topic of frequent stakeholder comment in recent years, including in comments submitted on posted drafts of NERC's business plans and budgets, in policy input comments provided by stakeholders to the Board, and in other interactions between stakeholders and NERC management and the Board. Stakeholders have expressed a desire for NERC to find ways to dampen the fluctuations in assessments from year to year, such as through management of penalty revenues, in order to provide greater predictability for LSEs in forecasting and budgeting for their assessment expenses.[13] NERC management has had numerous discussions with representatives of stakeholders and stakeholder groups and has received positive feedback on the concept of an Assessment Stability Reserve as a mechanism to reduce significant year-to-year variability in assessments. In conjunction with the Board's approval of the revised WCOR Policy at the February 2015 Board meeting, various stakeholders as well as Board members provided positive feedback and support for the Assessment Stabilization Reserve. The creation and use of an Assessment Stabilization Reserve to mitigate assessment volatility resulting from year-to-year fluctuations in penalty revenues and other causes should result in the changes in assessments, over time, more closely tracking changes in budgeted expenses and fixed asset expenditures.

Section 1107.2 of the NERC ROP states:

[13] Most recently, in stakeholder policy input provided to the NERC Board for its February 2015 meeting, a number of stakeholder entities and organizations expressed support for adoption of a mechanism to mitigate volatility in year-to-year assessments, including adoption and implementation of an assessment stability reserve. *See*: http://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Policy_Input_Package_February_2015.pdf.

> All funds from financial Penalties assessed in the United States received by the entity initiating the compliance monitoring and enforcement process shall be applied as a general offset to the entity's budget requirements for the subsequent fiscal year, if received by July 1, or for the second subsequent fiscal year, if received on or after July 1.[14]

However, §1107.4 of the ROP states: "Exceptions or alternatives to the foregoing provisions will be allowed if approved by NERC and by FERC or any other Applicable Governmental Authority." The revised WCOR Policy will allow NERC to place penalty funds received prior to July 1 of a year into the Assessment Stabilization Reserve, to be applied in a future budget to mitigate assessment volatility, rather than using the penalty funds as a general offset to NERC's budget requirement for the subsequent fiscal year. The Assessment Stabilization Reserve will provide a source of funding in future periods to offset increases in operating and fixed asset costs that would otherwise need to be funded by increases in assessments in that year. Thus, these funds will continue to be used to reduce assessments, but in a future period rather than the next budget year. Accordingly, NERC requests that, pursuant to §1107.4 of the ROP, the Commission approve the use of penalty monies provided for in the Assessment Stabilization Reserve category of the revised WCOR Policy as an exception to §1107.2.[15] As stated above, proposed injections of funds into the Assessment Stabilization Reserve in a particular year's budget, as well as proposed uses of funds from the Assessment Stabilization Reserve in a particular year's budget to reduce assessments, will be fully disclosed in the Business Plan and Budget, and will be subject to stakeholder comment in the budget development process, and to review and approval by the NERC Finance and Audit Committee and Board, and, ultimately, by

[14] A similar provision is set forth in the NERC policy, *Accounting, Financial Statement and Budgetary Treatment of Penalties Imposed and Received for Violations of Reliability Standards*.

[15] NERC considered proposing an amendment to ROP §1107 to explicitly provide for the use of penalty monies provided for in the Assessment Stabilization Reserve category of the revised WCOR Policy. NERC concluded, however, that it is preferable to first gain several years' experience with implementation of the Assessment Stabilization Reserve. NERC may propose an amendment to §1107 in the future, based on experience.

the Commission, as part of the budget approval process.[16]

B. Establishment of Guideline Upper and Lower Limits to the Amount of Operating Contingency Reserve to be Budgeted Each Year

In the revised WCOR Policy, the description of the Operating Contingency Reserve category includes the following provision:

> Except as otherwise approved by the Board, after review by the Finance and Audit Committee, the amount of the Operating Contingency Reserve shall be between three and one half (3.5%) percent and seven (7%) of the company's total expense and fixed asset budget minus the sum of the System Operator Certification and CRISP budgets, each of which have separate reserves.

As an example to translate the upper and lower bounds of the stated range into dollars, based on NERC's approved 2015 budget, 3.5% to 7% equates to $2 million to $4 million.[17] In its 2014 and 2015 budgets, NERC budgeted a total of $2 million in the unforeseen contingency and known contingency reserves, which in the revised WCOR Policy are combined into the Operating Contingency Reserve.

This provision is intended to provide guidance for management's annual recommendation to the Board as to the amount that should be budgeted for the Operating Contingency Reserve. It will place a reasonable bandwidth around the amount of the Operating Contingency Reserve that should be specified in each year's budget, subject to a decision by the NERC Board, following review by its Finance and Audit Committee, to budget more or less than the specified percentages. A recommendation by management to budget an amount less than or greater than

[16] The Commission has previously approved a proposal by NERC to use penalty monies other than as specified in §1107.2 of the ROP, in order to prevent a significant increase in assessments from the prior year's budget. Specifically, in its 2015 Business Plan and Budget Filing, NERC requested and received the Commission's approval to use a significant penalty payment that was received on July 9, 2014, to reduce the NERC assessment for the 2015 budget year, rather than hold the penalty payment to use as an offset to assessments in the 2016 budget. *See* 2015 Business Plan and Budget Filing at 77-79. NERC showed that with application of this penalty payment to offset the 2015 assessment, the increase in the 2015 assessment over the 2014 assessment would be approximately 20% ($1,000,000) lower than what the increase otherwise would be without this application.

[17] As stated in the quoted provision, the $2 million and $4 million figures were calculated by applying the stated percentages to NERC's 2015 total expense and fixed asset budget *less* the budgets for the System Operation Certification Program and the CRISP, each of which has its own reserve category in Operating Reserve under the revised WCOR Policy.

the stated range in the budget for a particular year will require additional justification. As noted earlier, the revised WCOR Policy specifies that the determination of the Operating Contingency Reserve amount for each year will take into consideration projected costs and risks of ongoing operations, projected resource requirements associated with significant ongoing or emerging reliability initiatives, capital spending forecasts, and other factors that the NERC Board, Finance and Audit Committee, and management consider appropriate.

In any event, the amount to be budgeted in each year for the Operating Contingency Reserve, whether within the guideline range or not, will be presented and explained in posted drafts of the business plan and budget, and will be subject to stakeholder review and comment, to review and approval by the NERC Board, and, finally, to review and approval by the Commission, as part of the annual business plan and budget review and approval process.

C. Revisions to the Guidelines and Authorities Applicable to Expenditures of Working Capital and Operating Reserve and the Guidelines and Authorities Required to Reallocate Budgeted Expenditures on an Intra-Year Basis

The revised WCOR Policy makes a number of revisions to the Guidelines and Authorities Applicable to Expenditures of Working Capital and Operating Reserves and the Guidelines and Authorities Required to Reallocate Budgeted Expenditures on an Intra-Year Basis. **First**, in the paragraph defining the authority of NERC's chief financial and administrative officer to draw on budgeted working capital reserves, a reference to "cash balance" requirements is deleted and a reference to "future excess cash flow" is changed to "future surplus cash flow." The deletion of the reference to "cash balance" requirements reflects that reserves needed to satisfy future obligations under leases, loan agreements and credit agreement is being moved from Working Capital to Operating Reserve under the revised Policy.

Second, NERC's president and CEO is authorized to approve expenditures from the System Operator Certification Reserve up to the amount set forth in the NERC budget. The System Operator Certification Reserve budget is established each year in consultation with the

PCGC, and, as stated in the WCOR Policy, expenditures from this reserve are made solely in support of the System Operator Certification Program based on guidance provided by the PCGC, which is responsible for overseeing the program.[18]

Third, the following guidelines and authorities will now apply to expenditures from the Operating Contingency Reserve and CRISP Reserve:

(i) The president and CEO can authorize expenditures up to $500,000, and management must report the expenditures to the Finance and Audit Committee of the Board no less frequently that in the quarterly budget variance report following the expenditure from the reserves.

(ii) For expenditures greater than $500,000 but less than $1,000,000, prior approval of the Finance and Audit Committee is required; and

(iii) For expenditures in excess of $1,000,000, approval of the Board is required after notice to and recommendation by the Finance and Audit Committee.

Previously, the president and CEO could authorize expenditures from the known contingencies reserve up to the amount set forth in NERC's budget and could authorize expenditures from the unforeseen contingencies reserve up to $250,000. Expenditures greater than $250,000 but less than $500,000 from the known contingencies reserve required approval of the Finance and Audit Committee, and expenditures greater than $500,000 from the known contingencies reserve required approval of the NERC Board after notice to and recommendation by the Finance and Audit Committee.

The revised WCOR Policy changes, as a matter of internal NERC governance and

[18] Under the current WCOR Policy, the president and CEO is authorized to make budgeted expenditures of excess funds associated with the Personnel Certification and Operator Training Program up to the amount set forth in the budget, and to authorize unbudgeted expenditures of these funds up to $250,000, with prior approval of the Finance and Audit Committee required for expenditures greater than $250,000 and less than $500,000, and Board approval required for expenditures in excess of $500,000. However, budget and expenditure decisions for the System Operator Certification Program, including uses of reserves, are made based on the PCGC's input.

oversight by its Board in accordance with its responsibilities, the levels of expenditures from the Operating Contingency Reserve that require approval by, respectively, the NERC president and CEO, the Finance and Audit Committee, and the NERC Board. These revisions notwithstanding, however, NERC will continue to comply with the filing and approval requirement of Paragraph 7(b)(ii):

> NERC will file for Commission review and approval Board-of-Trustees-approved proposals to expend $500,000 or more from operating reserves designated for "unforeseen contingencies" (as that term is defined in NERC's Working Capital and Operating Reserve Policy (Reserve Policy)). Each such filing will include supporting materials in sufficient detail to justify the proposed expenditure. The filing will be deemed approved if the Commission does not act on it or issue a tolling order extending the time for Commission action within thirty days of the filing date.
>
> [T]his requirement for Commission review and approval is triggered if any amount allocated from the unforeseen contingencies account of operating reserves plus any amount redirected from previously budgeted funds is, in the aggregate, $500,000 or more for any one specific project or major activity in a program area.

As the "known contingencies" and "unforeseen contingencies" categories of Operating Reserve are being replaced by a single Operating Contingency Reserve category, going forward NERC will treat the "unforeseen contingencies" references in Paragraph 7(b)(ii) as encompassing expenditures from the Operating Contingency Reserve.[19]

Fourth, the revised WCOR Policy eliminates the requirement that any expenditure of funds in excess of NERC's approved budget, inclusive of Working Capital and Operating Reserves, requires prior approval of the Board after notice to and recommendation of the Finance and Audit Committee. The revised Policy now sets forth the specific dollar amounts of expenditures from Operating Reserves categories that require approval by the Board, after notice

[19] In light of the specific purpose and funding sources of the CRISP Reserve and its limited uses, NERC considered not making the CRISP Reserve subject to the same guidelines and authorities as the Operating Contingency Reserve, but rather providing for expenditures from the CRISP Reserve to be subject to the determination of management and the CRISP participants (similar to the Operator Certification Reserve). However, given the nascent nature of the CRISP, NERC concluded that it would be better to obtain several years of experience with the CRISP and the CRISP Reserve before determining different guidelines and authorities are appropriate. NERC may propose different guidelines and authorities for the CRISP Reserve in the future, based on experience.

to and recommendation by the Finance and Audit Committee. As described below, the revised Policy also authorizes the president and CEO to reallocate budget underruns in one budget area to another budget area so long as the overall approved budget is not exceeded and the reallocations are reported in the quarterly variance reports.

Fifth, the revised WCOR Policy continues to specify that all expenditures of reserve funds are subject to applicable NERC policies and procedures, including currently effective procurement policies and delegations of authority, and shall be separately reported in the budget variance reports prepared by NERC management and included in the quarterly Finance and Audit Committee agenda materials that are posted on NERC's website.[20] However, this provision has been revised to specify that the applicable delegation of authority must be one that is approved by the president and CEO.

Sixth, the revised WCOR Policy eliminates the requirement that budgeted but unspent funds from a budget area must be transferred to the unforeseen contingency operating reserve before the president and CEO can expend such funds in other budget areas that require additional funding. The revised WCOR Policy specifies that the president and CEO can authorize the reallocation and expenditure of budgeted but unneeded funds from one budget area to another budget area, without the procedural step of first transferring the funds into the unforeseen contingency operating reserve, so long as the reallocation does not result in NERC's overall approved budget being exceeded. However, any such reallocation and expenditure of funds must be reported by management in NERC's quarterly budget variance reports which are submitted to and reviewed by the NERC Finance and Audit Committee. Further, NERC reiterates that any such expenditure and reallocation of budgeted funds will be subject to the filing and approval requirement of Paragraph 7(b)(ii) (quoted above) if the dollar amount specified in Paragraph 7(b)(ii) is reached or exceeded.

[20] The Finance and Audit Committee agenda materials and meeting minutes are posted on the NERC website at: http://www.nerc.com/gov/bot/FINANCE/Pages/2013FinanceandAuditCommittee.aspx.

Finally, the revised WCOR Policy eliminates the requirement that any FTE or headcount additions which are in excess of the total FTEs or total headcount set forth in NERC's approved business plan and budget for the year must be approved by the Board after review by NERC's Corporate Governance and Human Resources Committee and Finance and Audit Committee.

It is a customary principle of corporate governance that delegations of authority to board committees and the company CEO are determined by the board based on considerations the board deems relevant. As noted above, as a matter of internal governance and board oversight and responsibility, the levels of expenditures which require authorization within the organization by different levels of management, including the president and CEO, by board committees, and by the board, should be determined by the organization's board. Here, NERC's independent Board of Trustees has concluded that the increases in the levels of expenditures from the various reserves that may be authorized by, respectively, the president and chief operating officer and the Finance and Audit Committee, rather than by the Board, are appropriate and justified, based on the following considerations:

- First, given the size of NERC's budget, the Board (as well as the Finance and Audit Committee) concluded that it was appropriate that the president and CEO have greater authority to approve the use of reserves. The $250,000 limit on the president and CEO's authority in the current WCOR Policy represents less than 0.5% of NERC's approved 2015 budget.

- Second, over the past several years, NERC has put in place very robust and transparent financial reporting to the Finance and Audit Committee, the Board, stakeholders and the Commission.

- Third, over the past several years, NERC has implemented more robust internal control processes and procedures governing financial expenditures and vendor management.

- Fourth, under the revised WCOR Policy, the Working Capital Reserve, the Future Obligation Reserve, the System Operator Certification Reserve, the CRISP Reserve, and the Assessment Stabilization Reserve, each has a specific, limited objective and purpose or designated use of its funds, which limits and controls the expenditure of funds from the particular reserve category.

As noted throughout the foregoing description of the revised WCOR Policy, sources of funding for reserves, as well as planned uses of reserves, will be described in draft business plans

and budgets, subject to stakeholder review and comment, subject to review and approval by the NERC Finance and Audit Committee and then by the NERC Board, and finally subject to Commission approval. Expenditures of funds from reserves or reallocation of funds from one budget area to another during the year will continue to be reported in NERC's quarterly variance reports which are posted on its website, provided to the Commission, and discussed at quarterly Finance and Audit Committee meetings, and, if necessary under the Policy based on amount, will be approved by the Finance and Audit Committee or by the Board. Thus, any such uses or reallocations of funds will be publicly reported and completely transparent.[21]

Additionally, under the oversight and guidance of its Enterprise Risk Management Committee and Internal Controls Department, NERC has been continuously enhancing its internal controls processes, including controls and processes governing vendor procurement and management. These increased internal controls are reflected in the more detailed information on Consultant & Contracts expense that NERC has reported in its 2013, 2014 and 2015 Business Plans and Budgets submitted to the Commission.[22] As another example, NERC has recently updated its internal processes for vendor procurement and contract management, incorporating a requirement for a detailed, written explanation and justification for a proposed contract, including a description of the procurement method used, information on the proposed counterparty, descriptions of the proposed services, scope of work, costs and budget, and whether the expenditure is provided for in the current year budget. It also requires approvals by various levels of management, depending on the nature of the contract and the amount, as well as designation of management personnel responsible for vendor management and oversight.[23]

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[21] NERC also prepares monthly variance and reserve usage reports for internal use by management.

[22] *See, e.g.*, Attachment 2 (NERC Business Plan and Budget) to the 2015 Business Plan and Budget Filing, at 126-127 (Exhibit C).

[23] Additional information on enhanced controls over expenditures and enhanced financial reporting that NERC has put in place over the past two years, and has now had experience in implementing, was provided in NERC's 2015 Business Plan and Budget (*see* Attachment 2 to the 2015 Business Plan and Budget Filing at xvi-xvii) and in NERC's 2014 Business Plan and Budget Filing (*see Request of the North*

With the more detailed descriptions of the Working Capital and Operating Reserve categories and their purposes and limitations in the revised WCOR Policy, along with the combination of highly transparent budgeting, variance reporting and approval processes and increasingly stronger internal controls, the increases in authorization levels for expenditures from the various reserves categories are both warranted and appropriate.

The deletion of the provision requiring that funds budgeted for but not needed in a budget area must be transferred to the unforeseen contingency operating reserve before they can be expended in another budget area where greater resources are needed, provides for greater administrative efficiencies and eliminates an unnecessary procedural step. Further, the business plan and budget development and approval process necessitates that the business plan and budget for a year must be essentially finalized six months before the start of that year and 18 months before the end of that year. With so much lead time from budget finalization to actual manifestation of resource and expenditure needs, it is extremely difficult to anticipate how actual resource needs may vary from what was projected in developing the budget for each program area. The ability for management to reallocate budgeted funds from budget areas for which fewer resources are needed than anticipated, to budget areas for which greater resources are needed than anticipated (so long as the total NERC budget is not exceeded), provides flexibility needed for management to effectively manage NERC's resources during the year to accomplish the objectives of all of its programs. However, as provided in the revised WCOR Policy, all such reallocations must be reported by management in the quarterly variance reports, thereby providing stakeholders and the Commission with complete visibility of any such reallocations. Further, all such reallocations will be subject to the filing and approval requirement of Paragraph 7(b)(ii) if the amount specified in Paragraph 7(b)(ii) is reached or exceeded.

American Electric Reliability Corporation for Acceptance of its 2014 Business Plan and Budget and the 2014 Business Plans and Budgets of Regional Entities and for Approval of Proposed Assessments to Fund Budgets, filed August 23, 2013, in Docket No. RR13-9-000, at 9-10 and Attachment 2 (NERC 2014 Business Plan and Budget) at 16-17).

Finally, the deletion from the WCOR Policy of the provision pertaining to increases in FTEs and headcount is appropriate because increases in FTEs and headcount are not directly related to the management of Operating Reserve and are not appropriately included in a Working Capital and Operating Reserve Policy. Further, FTE and headcount numbers are otherwise subject to ongoing oversight by the NERC Corporate Governance and Human Resources Committee, the Finance and Audit Committee, and the Board. Additionally, the quarterly variance reports to the Finance and Audit Committee and the Board, which are publicly posted, available to stakeholders, and provided to the Commission, include information on actual versus budgeted FTEs. If an increase in FTEs or headcount during a year above the budgeted levels requires either the expenditure of funds from an applicable reserve category or the reallocation of funds from one budget area to another, then the WCOR Policy provides for the appropriate review, approval and reporting of the expenditures.

D. NERC Board Approval of the Revised WCOR Policy

The NERC Board of Trustees approved the revised WCOR Policy at its February 12, 2015 meeting.

E. Request for Prompt Action on this Filing

NERC respectfully requests that the Commission consider and act on this request, by issuing an order approving the revised WCOR Policy on or before May 21, 2015 (which is the scheduled date for the Commission's monthly public meeting for May). Approval of the revised WCOR Policy by May 21 will enable NERC to incorporate the revised WCOR Policy into its business planning and budgeting process for the 2016 Business Plan and Budget, including proposing specific amounts to be injected into and withdrawn from the Working Capital and the various categories of Operating Reserves in the 2016 Business Plan and Budget. Although NERC's 2016 Business Plan and Budget is not required to be filed with the Commission for approval until August 24, 2015, NERC will be posting drafts of its 2016 Business Plan and

Budget for stakeholder review and comment beginning in late May. Inclusion and explanation of specific proposed Working Capital and Operating Reserve injection and withdrawal amounts, based on the revised WICOR Policy, in the posted drafts of the 2016 Business Plan and Budget will maximize the opportunities for stakeholders to understand and comment on these proposals.

IV. CONCLUSION

The North American Electric Reliability Corporation respectfully requests that the Commission approve NERC's revised Working Capital and Operating Reserve Policy, **Attachment 1** to this filing, including approving, pursuant to §1107.4 of the NERC Rules of Procedure, the use of penalty monies as provided for in the Assessment Stabilization Reserve category of Operating Reserve in the WCOR Policy, as an exception to §1107.2 of the ROP. NERC respectfully requests an order approving its request on or before May 21, 2015.

Respectfully submitted,

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ATTACHMENT 1

REVISED WORKING CAPITAL AND OPERATING RESERVE POLICY

CLEAN VERSION

Working Capital and Operating Reserve Policy

This policy governs the determination of the company's annual working capital and operating reserve requirements, as well as the authorization of management to access these funds.

The company's working capital and operating reserve requirements shall be set forth separately in the company's business plan and budget.

Working Capital represents the amount of funds necessary to satisfy the company's projected cash flow needs during the budget year, taking into account the projected timing of the receipt of funding and timing of capital and operating expenses. In addition to the foregoing, the company shall also maintain a line of credit, with a financial institution, in such amount and upon such terms and conditions, approved by the company's Finance and Audit Committee and the NERC Board of Trustees ("Board").

Operating Reserves represent reserves necessary to support operations, including contingencies. Operating Reserves shall be divided into four categories: (1) reserves that are being held in order to satisfy future obligations under any lease, credit, loan agreement or other obligation to which the company is a party (the "**Future Obligation Reserve**"); (2) reserves to support the System Operator Certification Program Area Reserve (the "**System Operator Certification Reserve**"); (3) reserves to support the Cybersecurity Risk Information Sharing Program, known as CRISP (the "**CRISP Reserve**"); (4) reserves to fund reasonable and appropriate expenditures that were not assumed likely or anticipated in the company's budget or for which the timing was uncertain (the "**Operating Contingency Reserve**"). In addition to the foregoing reserves, funds may periodically be set aside in a separate reserve and released in future periods in order to mitigate wide year-to-year variations in assessments (the **"Assessment Stabilization Reserve**").

The amount of the company's **Working Capital, Future Obligation Reserve**, **System Operator Certification Reserve**, **CRISP Reserve**, **Operating Contingency Reserve** and **Assessment Stabilization Reserve** shall be identified separately and quantified each year in the business plan and budget submitted to and reviewed by the Finance and Audit Committee, and approved by the Board.

The following additional guidelines shall apply to the determination of the company's Operating Reserves and Assessment Stabilization Reserve:

Future Obligation Reserve

The Future Obligation Reserve includes funding that has been received to satisfy future obligations under lease, credit, loan or other agreement to which the company is a party. An example is office lease funding that is in excess of actual office rent expense due to a landlord's partial abatement of rent and a budgeted lease expense based on the straight line amortization of rent expense over the term of the lease. In such a case, this surplus funding is being held to offset future rent

expense. Another possible example includes reserves or sinking funds requirements to meet covenant or other obligations under loan or other credit agreements.

System Operator Certification Reserve

The System Operator Certification Reserve supports the system operator certification program, and includes surplus funding from operator certification and testing fees that are above incurred expenses. Consistent with the intent of Section 604.4.10 of the Rules of Procedures, this reserve shall be used solely to support operator testing and certification needs, as determined by the company and the Personnel Certification Governance Committee.

CRISP Reserve

The CRISP Reserve is maintained to support CRISP. The CRISP Reserve shall be held in a separate bank account and used solely for CRISP funding.

Operating Contingency Reserve

The Operating Contingency Reserve are reserves for contingencies that were not anticipated, assumed to be likely or the timing of which was uncertain, at the time of preparation and approval of the company's business plan and budget. The determination of the amount of the Operating Contingency Reserve shall take into consideration the projected costs and risks of ongoing operations, projected resource requirements associated with significant ongoing or emerging reliability initiatives, capital-spending forecasts and other factors that the Board, Finance and Audit Committee, and management consider appropriate. Examples of unforeseen contingencies might include supplemental resources required to assist in the evaluation of significant unforeseen events affecting the Bulk-Power System or to address regulatory directives not final at the time of budgeting. Except as otherwise approved by the Board, after review by the Finance and Audit Committee, the amount of the Operating Contingency Reserve shall be between three and one half (3.5%) percent and seven (7%) percent of the company's total expense and fixed asset budget minus the sum of the System Operator Certification and CRISP budgets, each of which have separate reserves.

Assessment Stabilization Reserve

The goal of the Assessment Stabilization Reserve is to mitigate assessment volatility and have changes in annual assessments track, within a reasonable band, changes in the company's total annual budget, with the total budget reflecting prudent fiscal discipline and good stewardship of resources. Assessment stabilization funds will be used when available to help stabilize assessments and mitigate year-to-year swings in assessments, which can result from a variety of factors, including but not limited to the application of penalty funds, surplus funds available from a prior period, a need to replenish the Operating Contingency Reserve, or significant but relatively short term operating or capital spending needs. The amount of the Assessment Stabilization Reserve which is budgeted in any given year shall be determined based on a review of a three-year rolling forecast of assessments, as well as the availability of surplus funds and penalty funds to fund this reserve. Except as otherwise approved by the Board, funds in the Assessment Stabilization Reserve may not be used for any purpose inconsistent with the goal of the reserve set forth in this paragraph.

Guidelines and Authorities Applicable to Expenditures of Working Capital and Operating Reserves

The following guidelines, limitations and authorities shall apply to expenditures of working capital and operating reserves.

1. The chief financial and administrative officer shall have the authority to draw on budgeted working capital reserves to the extent necessary to satisfy daily cash flow requirements. To the extent necessary to meet projected cash flow and cash balance requirements, any such draws of working capital reserves shall, to the extent possible, be promptly replenished from future surplus cash flow.
2. The company's president and chief executive officer is authorized to approve expenditures of System Operator Certification Reserves up to the amount set forth in the company's budget.
3. For Operating Contingency Reserve and CRISP Reserve expenditures:
    i. The president and chief executive officer is authorized to make expenditures up to $500,000 and management shall report such expenditures to the Finance and Audit Committee no less frequently than in the quarterly company budget variance report following the expenditure of such reserves;
    ii. For expenditures greater than $500,000 but less than $1,000,000, prior approval of the Finance and Audit Committee is required; and
    iii. For expenditures in excess of $1,000,000, approval of the Board is required, after notice to and recommendation by the Finance and Audit Committee.
4. The company shall segregate Future Obligation Reserves to ensure they are available for use in satisfying such future obligations; provided however, such funds shall also be available to satisfy any coverage and liquidity requirements under the terms of any loan or credit agreement to which the company is a party.

All expenditures of reserve funds are subject to other applicable company policies and procedures, including currently effective procurement policies and delegations of authority approved by the president and chief executive officer, and shall be separately reported in the budget variance reports prepared by management, and included in the quarterly Finance and Audit Committee agenda materials that are posted on the company's website.

The procedures set forth in Section 1108 of the Rules of Procedure, including Board and FERC approval, shall continue to apply in circumstances where the company requires funding between normal annual budget cycles in excess of amounts available through approved assessments, working capital and operating reserve resources.

Guidelines and Authorities Required to Reallocate Budgeted Expenditures on an Intra-year Basis

During the course of the year, events may unfold such that some approved budget areas may run below budget, making funds available to satisfy other resource needs based on changing priorities. In the event such under runs occur, the president and chief executive officer shall have the authority to reallocate and expend such funds, provided that such reallocation and expenditure does not result in the company's overall approved budget being exceeded and such expenditures shall be reported by management in the company's quarterly budget variance reports, which are submitted to and reviewed by the Finance and Audit Committee.

ATTACHMENT 2

REVISED WORKING CAPITAL AND OPERATING RESERVE POLICY

REDLINED VERSION

Working Capital and Operating Reserve Policy

This policy governs the determination of the company's annual working capital and operating reserve requirements ~~which are included in the company's annual business plan and budget and~~, as well as the authorization of management to access these funds.

The company's working capital ~~requirement~~and operating reserve requirements shall be set forth separately in the company's business plan and budget.

Working Capital represents the amount of funds necessary to satisfy the company's projected cash flow ~~and cash balance requirements. Cash flow and cash balance requirements shall be determined based on a review of~~ needs during the budget year, taking into account the projected ~~(a) cash flow needs~~ timing of the receipt of funding and ~~(b) cash balances reasonably~~ timing of capital and operating expenses. In addition to the foregoing, the company shall also maintain a line of credit, with a financial institution, in such amount and upon such terms and conditions, approved by the company's Finance and Audit Committee and the NERC Board of Trustees ("Board").

Operating Reserves represent reserves necessary to ~~meet current and~~ support operations, including contingencies. Operating Reserves shall be divided into four categories: (1) reserves that are being held in order to satisfy future obligations under any ~~covenant, financial~~ lease, credit, loan agreement or other obligation ~~under the terms of any loan, credit, or lease agreement~~ to which the company is a party~~. To the extent that during the year the working capital cash balances maintained to satisfy any covenant, financial or other obligations under the terms of any loan, credit or lease agreement are reduced, such excess cash balance will be transferred to the company's operating reserve for unforeseen contingencies and subject~~ (the "**Future Obligation Reserve**"); (2) reserves to ~~the guidelines and authorities applicable~~support the System Operator Certification Program Area Reserve (the "**System Operator Certification Reserve**"); (3) reserves to support the Cybersecurity Risk Information Sharing Program, known as CRISP (the "**CRISP Reserve**"); (4) reserves to fund reasonable and appropriate expenditures ~~thereof set forth below.~~that were not assumed likely or anticipated in the company's budget or for which the timing was uncertain (the "**Operating Contingency Reserve**"). In addition to the foregoing reserves, funds may periodically be set aside in a separate reserve and released in future periods in order to mitigate wide year-to-year variations in assessments (the **"Assessment Stabilization Reserve**").

The ~~company's operating reserves shall include (1) an amount necessary to satisfy known contingencies where the specific timing and~~ amount ~~is uncertain, (2) an amount available to be utilized for unforeseen contingency and (3) excess funds applicable to the Personnel Certification and Operator Training Program.~~

~~The amount of the company's working capital and operating reserves, by category,~~of the company's **Working Capital, Future Obligation Reserve**, **System Operator Certification Reserve**, **CRISP Reserve**, **Operating Contingency Reserve** and **Assessment Stabilization Reserve** shall be ~~separately~~ identified

separately and quantified each year in the business plan and budget submitted to and ~~approved by the Board of Trustees. Transfers of working capital to operating reserves and transfers of operating reserve funds between categories shall require approval of the Board of Trustees, after review and recommendation by the Finance and Audit Committee.~~reviewed by the Finance and Audit Committee, and approved by the Board.

The following additional guidelines shall apply to the determination of the company's ~~operating reserves.~~

~~(1)~~ ~~Known Contingencies Where the Amount~~Operating Reserves and ~~Timing Are Uncertain~~Assessment Stabilization Reserve:

~~This category of operating reserves represents estimated funding reserves known contingencies where the timing and amount of funding to satisfy the contingency when it materializes is uncertain. An example would be the need for additional resources to address a requirement or process where regulatory or other governmental authorizations or directives are pending or anticipated but an order has not yet been issued so the amount of the impact and timing is uncertain, but management has nevertheless concluded that additional resources are likely to be required.~~

~~(2) Unforeseen Contingencies~~

~~This category of operating reserves represents a funding reserve for unknown contingencies which~~

Future Obligation Reserve

The Future Obligation Reserve includes funding that has been received to satisfy future obligations under lease, credit, loan or other agreement to which the company is a party. An example is office lease funding that is in excess of actual office rent expense due to a landlord's partial abatement of rent and a budgeted lease expense based on the straight line amortization of rent expense over the term of the lease. In such a case, this surplus funding is being held to offset future rent expense. Another possible example includes reserves or sinking funds requirements to meet covenant or other obligations under loan or other credit agreements.

System Operator Certification Reserve

The System Operator Certification Reserve supports the system operator certification program, and includes surplus funding from operator certification and testing fees that are above incurred expenses. Consistent with the intent of Section 604.4.10 of the Rules of Procedures, this reserve shall be used solely to support operator testing and certification needs, as determined by the company and the Personnel Certification Governance Committee.

CRISP Reserve

The CRISP Reserve is maintained to support CRISP. The CRISP Reserve shall be held in a separate bank account and used solely for CRISP funding.

Operating Contingency Reserve

The Operating Contingency Reserve are reserves for contingencies that were not anticipated, assumed to be likely or the timing of which was uncertain, at the time of preparation and approval of the ~~business plan and budget.~~company's business plan and budget. The determination of the amount of the Operating Contingency Reserve shall take into consideration the projected costs and risks of ongoing operations, projected resource requirements associated with significant

ongoing or emerging reliability initiatives, capital-spending forecasts and other factors that the Board, Finance and Audit Committee, and management consider appropriate. Examples of unforeseen contingencies might include supplemental resources required to assist in the evaluation of significant unforeseen events affecting the ~~bulk power system, such as the February Cold Weather Event and Southwest Outage or to address unforeseen regulatory directives.~~ Bulk-Power System or to address regulatory directives not final at the time of budgeting. Except as otherwise approved by the Board, after review by the Finance and Audit Committee, the amount of the Operating Contingency Reserve shall be between three and one half (3.5%) percent and seven (7%) percent of the company's total expense and fixed asset budget minus the sum of the System Operator Certification and CRISP budgets, each of which have separate reserves.

~~(3) Excess Funds applicable to the Personnel Certification and Operator Training Program~~
~~In the event the company realizes higher levels of funding from operator certification and training above incurred expenses, this excess funding shall constitute a separate category of operating reserve and shall be used solely for operator training and certification needs, as determined by the company and the Personnel Certification Governance Committee. This is consistent with the intent of Section 604.4.10 of the Rules of Procedures.~~

Assessment Stabilization Reserve

The goal of the Assessment Stabilization Reserve is to mitigate assessment volatility and have changes in annual assessments track, within a reasonable band, changes in the company's total annual budget, with the total budget reflecting prudent fiscal discipline and good stewardship of resources. Assessment stabilization funds will be used when available to help stabilize assessments and mitigate year-to-year swings in assessments, which can result from a variety of factors, including but not limited to the application of penalty funds, surplus funds available from a prior period, a need to replenish the Operating Contingency Reserve, or significant but relatively short term operating or capital spending needs. The amount of the Assessment Stabilization Reserve which is budgeted in any given year shall be determined based on a review of a three-year rolling forecast of assessments, as well as the availability of surplus funds and penalty funds to fund this reserve. Except as otherwise approved by the Board, funds in the Assessment Stabilization Reserve may not be used for any purpose inconsistent with the goal of the reserve set forth in this paragraph.

Guidelines and Authorities Applicable to Expenditures of Working Capital and Operating Reserves

The following guidelines, limitations and authorities shall apply to expenditures of working capital and operating reserves.

1. The ~~Chief Financial~~chief financial and ~~Administrative Officer~~administrative officer shall have the authority to draw on budgeted working capital reserves to the extent necessary to satisfy daily cash flow ~~and cash balance~~ requirements. To the extent necessary to meet projected cash flow and cash balance requirements, any such draws of working capital reserves shall, to the extent possible, be promptly replenished from future ~~excess~~surplus cash flow.

2. ~~For expenditures of operating reserves for budgeted known contingencies, the~~The company's president and chief executive officer is authorized to ~~expend such reserves~~approve expenditures of System Operator Certification Reserves up to the amount set forth in the company's budget.

3. ~~For budgeted~~For Operating Contingency Reserve and CRISP Reserve expenditures ~~of excess funds associated with the Personnel Certification and Operator Training Program, the company's~~:

   ~~3.~~i. The president and chief executive officer is authorized to ~~expend such reserves up to the amount set forth~~ make expenditures up to $500,000 and management shall report such expenditures to the Finance and Audit Committee no less frequently than in the ~~company's~~ quarterly company budget~~.~~ variance report following the expenditure of such reserves;

~~4. For expenditures of operating reserves budgeted for unforeseen contingencies, including the expenditure of excess working capital reserves which are transferred to the company's operating reserve for unforeseen contingencies, and for unbudgeted expenditures of excess funds associated with the Personnel Certification and Operator Training Program:~~

   ~~i. The president and chief executive officer shall have authority to make expenditures up to $250,000;~~

   ii. For expenditures greater than $~~250~~500,000 but less than $~~500~~1,000,000, prior approval of the Finance and Audit Committee is required; and

   iii. For expenditures in excess of $~~500~~1,000,000, approval of the Board ~~of Trustees~~ is required, after notice to and recommendation by the Finance and Audit Committee.

~~5.~~4. ~~To the extent that working capital reserves include reserves to satisfy future financial, covenant or other obligations, the~~The company shall segregate ~~such funds~~Future Obligation Reserves to ensure they are available for use in satisfying such future ~~financial, covenant or other~~ obligations; provided however ~~that,~~ such funds shall also be available to satisfy any coverage and liquidity requirements under the terms of any loan or credit agreement to which the company is a party.

~~6. Any expenditure of funds in excess of the company's approved budget, inclusive of budgeted working capital and operating reserves, requires the prior approval of the Board of Trustees, after notice to and recommendation of the Finance and Audit Committee.~~

All expenditures of ~~contingency~~reserve funds are subject to other applicable company policies and procedures, including currently effective procurement policies and delegations of authority approved by the president and chief executive officer, and shall be separately reported in the budget variance reports prepared by management, and included in the quarterly Finance and Audit Committee agenda materials~~, which~~ that are posted on the company's website.

The procedures set forth in Section 1108 of the Rules of Procedure, including Board ~~of Trustees~~ and FERC approval, shall continue to apply in circumstances where the company requires funding between normal

annual budget cycles in excess of amounts available through approved assessments, working capital and operating reserve resources.

Guidelines and Authorities Required to Reallocate Budgeted Expenditures on an Intra-year Basis

During the course of the year, events may unfold such that some approved budget areas may run below budget, making funds available to satisfy other resource needs based on changing priorities. In the event such under runs occur, ~~these excess funds shall be added to the unforeseen contingency operating reserve and~~ the president and chief executive officer shall have the authority to reallocate and expend such funds, provided that such reallocation and ~~management shall also be responsible for reporting~~expenditure does not result in the company's overall approved budget being exceeded and such expenditures~~, in the same manner as~~ shall be reported by management in the company's quarterly budget variance reports, which are submitted to and reviewed by the ~~expenditure of funds for other unforeseen contingencies set forth above~~Finance and Audit Committee.

~~**Addition of Unbudgeted FTE or Headcount Additions**~~

~~Any FTE or headcount additions, regardless of the source of and availability of funding, which are in excess of the total FTEs or total headcount, respectively, set forth in the company's approved business plan and budget for the applicable budget year shall require approval of the Board of Trustees, after review by the Corporate Governance and Human Resources Committee and the Finance and Audit Committee.~~

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

February 27, 2015

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Petition of the North American Electric Reliability Corporation for Approval of Amendments to the Bylaws of the Texas Reliability Entity, Inc.
Docket No. RR15-___-000

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits the "Petition of the North American Electric Reliability Corporation for Approval of Amendments to the Bylaws of the Texas Reliability Entity, Inc." ("Petition"). This filing consists of various amendments to the Bylaws of the Texas Reliability Entity, Inc. ("Texas RE") found in Exhibit B of the Regional Delegation Agreement between NERC and Texas RE. The amendments to the Texas RE Bylaws do not affect Texas RE's Regional Entity functions, and they continue to satisfy the five governance criteria in the Regional Delegation Agreement.

This filing consists of: (1) this transmittal letter, (2) the narrative text of the Petition following this transmittal letter, and (3) Attachments 1 and 2 to the Petition, which contain a clean version and a redline version of the proposed amendments to the Texas RE Bylaws, respectively. All of these documents are transmitted in a single PDF file.

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Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Please contact the undersigned if you have any questions concerning this filing.

Respectfully submitted,

/s/ Andrew C. Wills
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UNITED STATES OF AMERICA
Before the
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	**)** **)**	**Docket No. RR15-___-000**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF AMENDMENTS TO THE BYLAWS OF THE TEXAS RELIABILITY ENTITY, INC.

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February 27, 2015

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ATTACHMENTS

Attachment 1: Amended and Restated Bylaws of the Texas Reliability Entity, Inc. – Clean version

Attachment 2: Amended and Restated Bylaws of the Texas Reliability Entity, Inc. – Redline version

I. INTRODUCTION

Pursuant to § 215(e)(4) of the Federal Power Act[1] and 18 C.F.R. §§ 39.8 and 39.10 (2013), the North American Electric Reliability Corporation ("NERC") requests the approval of the Federal Energy Regulatory Commission ("FERC or Commission") for proposed amendments to the Bylaws of the Texas Reliability Entity, Inc. ("Texas RE"), which are currently in Exhibit B of the Regional Delegation Agreement between NERC and Texas RE.

The currently effective version of the Texas RE Bylaws was filed at FERC by NERC in Docket No. RR13-4-000 and was approved on June 12, 2013.[2] On February 12, 2015, the NERC Board of Trustees approved amendments to the Texas RE Bylaws that are the subject of this Petition. Because these Bylaws are "Regional Entity Rules" as defined in 18 C.F.R. § 39.10, NERC submits these proposed amendments for Commission approval in accordance with the process for amending a Regional Entity Rule found in 18 C.F.R. § 39.10. These amendments implement the following changes, among others, to the Texas RE Bylaws:

(a) clarify term limits and the selection process for Independent Directors;

(b) provide detail regarding stock restrictions for Independent Directors;

(c) prescribe the process for the selection and approval of corporate officers;

(d) revise the term limit for members of the Member Representatives Committee ("MRC"); and

(e) implement other stylistic edits to remove unnecessary language and streamline the Bylaws.

[1] 16 U.S.C. § 824o (2012).

[2] *North American Electric Reliability Corporation*, Docket No. RR13-4-000 (June 12, 2013) (unpublished delegated letter order).

The proposed amendments to the Texas RE Bylaws do not raise any reliability-related issues and do not affect the qualifications of Texas RE to serve as a Regional Entity with delegated authority from NERC. The revised Texas RE Bylaws continue to satisfy the five governance criteria in the Regional Delegation Agreement.

Attachments 1 and **2** to this Petition are clean and redline versions, respectively, of the proposed amended Texas RE Bylaws. The redlined text in **Attachment 2** shows the proposed amendments to the Texas RE Bylaws.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[3]

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*Persons to be included on the Commission's official service list

[3] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2012), to allow the inclusion of more than two persons on the service list in this proceeding.

III. PROPOSED AMENDMENTS TO EXHIBIT B OF THE REGIONAL DELEGATION AGREEMENT BETWEEN NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION AND TEXAS RELIABILITY ENTITY, INC.

The proposed amendments to the Bylaws of Texas RE, found in Exhibit B of the Texas RE Regional Delegation Agreement, address several Texas RE-specific corporate governance matters by aligning the Bylaws with current practices and implementing various stylistic, grammatical, and typographical updates. The discussion in the following subsections outlines the specific proposed amendments to the Texas RE Bylaws.

A. ARTICLE I: DEFINITIONS

Article I is amended to replace the term "Initial Director" with "Originally Elected Independent Director" under Section 1(o) and to implement an associated definition to reflect this change. The term "Initial Director," while relevant when the Bylaws were last approved, is no longer necessary in the context of the current Texas RE Bylaws. As such, all references to that term throughout the document have been removed. The new term, "Originally Elected Independent Director," is included to identify those Directors who were elected in the first election of Texas RE on June 2, 2010.

B. ARTICLE II: PURPOSE

Because "ERCOT Region" is defined in the definitions in Article I, Section 1(g), the unnecessarily detailed and repetitive language describing the geographic boundaries of the ERCOT Region is removed from Section 3 of Article II.

C. ARTICLE III: MEMBERSHIP

The process for member registration and renewal in Article III Section 2 is streamlined, and it is improved to remove unneeded language, update defined terms, and to ensure consistency with other sections of the Texas RE Bylaws.

D. ARTICLE IV: BOARD OF DIRECTORS

In the description of qualifications for Independent Directors in Section 2(a)(2), references to the term "ERCOT Region Market Participant" are deleted because ERCOT's definition of "Market Participant," which includes "any entity that qualifies for ERCOT membership," is overly broad and difficult to apply. Additional language is added to Section 2(a)(2)(iv) to clarify that stock ownership restrictions for Independent Directors, their immediate family, and members of their household are ongoing and apply to stocks and bonds of NERC Registered Entities and affiliates. The revisions further clarify that ownership in broadly diversified mutual funds or similar funds, which may include stocks or bonds in NERC Registered Entities or affiliates, are expressly excepted from this restriction.

In Section 2(b), revisions are made to remove the reference to the previously defined term "Initial Director" and to clarify that the first terms of the Originally Elected Independent Directors do not count for purposes of term limits. Similarly, the first term of an Independent Director who is elected to fill an unexpired term in the event of a vacancy does not count for purposes of term limits. To maintain consistency with changes in Article IX, Section 2, the term of Affiliated Directors is changed from one year to two years.

In Section 2(c), references to the terms "Initial Director" and "Initial Nominating Committee" are deleted. The composition of the Nominating Committee is revised to ensure that there are two Independent Directors and one Affiliated Director on the Committee, consistent

with recent practice, thereby removing other limitations on the composition of the Nominating Committee. Section 2(c) is also edited to allow the Board Chair to select the Chair of the Nominating Committee and to clarify that notices of Nominating Committee meetings do not need to be publicly posted. With respect to the nomination process for Board members, the requirement that the Nominating Committee interview qualified candidates is removed.

Additional revisions throughout Article IV implement stylistic and typographical changes, updates, and corrections and improve consistency within these sections and with other sections of the Texas RE Bylaws.

E. ARTICLE V: MEETINGS OF MEMBERS OF THE CORPORATION

Section 1(a) is edited to clarify that the annual meeting will be held during the month of December. Other revisions are made in Section 1(b) and Section 2(a) that implement various stylistic and typographical changes, updates, and corrections to provide clarity and consistency within these sections and with other sections of the Texas RE Bylaws.

F. ARTICLE VI: MEETINGS OF THE BOARD OF DIRECTORS

In Section 3, references to the "Initial Directors" and the "Initial Board" are deleted. Language regarding emergency meetings, originally included in Section 4, has been deleted and moved to a newly created Section 7 of Article VI. Minor stylistic revisions and updates are made in Section 5 and Section 6 which improve clarity and consistency within this Section and with other Sections of the Texas RE Bylaws.

G. ARTICLE VII: OFFICERS

Language in Section 1 is revised to streamline the Board process for selecting the CEO and other officers of the corporation so that the Board has the authority to elect the CEO and

ratify the selection of other Officers made by the CEO. Section 3 is also amended to define the process for the CEO to select an Assistant Corporate Secretary, which the CEO may do at his or her discretion, and to explain that the Assistant Corporate Secretary is not an officer of the corporation. Further, several additional revisions are made throughout Article VII to remove duplicative language, to implement various stylistic changes and updates, and to improve consistency within this Section and other Sections of the Texas RE Bylaws.

H. ARTICLE IX: MEMBER REPRESENTATIVES COMMITTEE

In Section 2, the term length for members of the MRC and the length of tenure for chair and vice chair of the MRC is changed from one year to two years. Section 3 is revised to provide a new reference point for calculating the length of time for accepting nominations for candidates for the MRC, and the one-week period for notice of meetings of the MRC in Section 6 is changed to a period of five days. A parenthetical is added to broaden the scope of the term "Member(s)" or "Member Representative's Organization" in Sections 2, 3, and 9. Specifically, the parenthetical clarifies that when used in the context of an entity's representatives in the MRC, the terms "Member(s)" or "Member Representative's Organization" may also refer to "the Member's parent, subsidiary, or other Affiliate."

Additional revisions are made throughout Article IX to remove outdated references and to improve clarity and consistency within these sections and other sections of the Texas RE Bylaws.

IV. CONCLUSION

NERC respectfully requests that the Commission approve the proposed amendments to the Texas RE Bylaws, found in Exhibit B of the Texas RE Regional Delegation Agreement and shown in clean and redline form in **Attachment 1** and **Attachment 2** to this Petition, respectively, as amendments to Regional Entity Rules.

Respectfully submitted,

/s/ Andrew C. Wills

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Counsel for North American Electric Reliability Corporation

Dated: February 27, 2015

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 27th day of February, 2015.

/s/ Andrew C. Wills
Andrew C. Wills

Counsel for North American Electric Reliability Corporation

Attachment 1:

Amended and Restated Bylaws of the
Texas Reliability Entity, Inc.
– Clean version

AMENDED AND RESTATED BYLAWS

OF

TEXAS RELIABILITY ENTITY, INC.

(A Texas Non-Profit Corporation)

Approved by Membership –November 14, 2014

Approved by Federal Energy Regulatory Commission –_____

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ARTICLE I.
DEFINITIONS

Section 1. Definitions. The capitalized terms used in these Bylaws of Texas Reliability Entity, Inc. (the "Corporation" or "Texas RE"), shall have the meanings set forth below, or if not set forth below, shall have the meanings given them in the NERC Rules of Procedure.

(a) "Affiliate" means any entity controlling, controlled by or under common control with the entity under consideration, and includes any entity (i.e., any commercial enterprise) in any of the following relationships: (i) an entity that directly or indirectly owns or holds at least five percent of the voting securities of another entity, (ii) an entity in a chain of successive ownership of at least five percent of the voting securities of another entity, (iii) an entity which shares a common parent with or is under common influence or control with another entity or (iv) an entity that actually exercises substantial influence or control over the policies and actions of another entity. Evidence of influence or control shall include the possession, directly or indirectly, of the power to direct or cause the direction of the management and/or policies and procedures of another, whether that power is established through ownership or voting of at least five percent of the voting securities or by any other direct or indirect means. In cases where the level of control or influence is disputed, the Board shall have discretion to determine whether or not the entities are Affiliates of one another. Membership in Texas RE shall not create an affiliation with Texas RE.

(b) "Board" means the Board of Directors of the Corporation.

(c) "Bulk Power System" or "BPS" means facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and facilities generating electric energy as needed to maintain transmission system reliability, but does not include facilities used in the local distribution of electricity.

(d) "Delegated Authority" means the authority delegated by NERC to the Corporation to propose and enforce NERC Reliability Standards and perform other reliability-related activities in the ERCOT Region under the Delegation Agreement executed by NERC and the Corporation and approved by the Federal Energy Regulatory Commission, pursuant to Section 215 of the Federal Power Act (16 U.S.C. §824o).

(e) "Delegation Agreement" means the agreement between the Corporation and NERC and approved by FERC which describes the Delegated Authority and may be amended from time to time.

(f) "Electric Reliability Organization" or "ERO" means the organization that is certified by FERC pursuant to Section 39.3 of its regulations, and has received recognition by appropriate regulatory authorities in Canada and Mexico, as applicable, to establish and enforce Reliability Standards for the Bulk Power Systems of the respective countries and that has entered into a delegation agreement with the Corporation pursuant to which the Electric Reliability Organization delegates enforcement authority for Reliability Standards for the Bulk Power System in the ERCOT Region. NERC was certified as the ERO on July 20, 2006.

(g) "ERCOT Region" means the geographic area and associated transmission and distribution facilities that are not synchronously interconnected with electric utilities operating outside the jurisdiction of the Public Utility Commission of Texas.

(h) "FERC" means the Federal Energy Regulatory Commission.

(i) "Independent Director" means a person who is not (a) an officer or employee of the Corporation; (b) a NERC Registered Entity or Member or an officer, director, or employee of a Member of the Corporation; or (c) an officer, director, or employee of any company or entity that would reasonably be perceived as having a direct financial interest in the outcome of Board decisions or having a relationship that would interfere with the exercise of independent judgment in carrying out the responsibilities of a Director, as more specifically described in Article IV of these Bylaws.

(j) "Member" means a member of the Corporation pursuant to Article III of these Bylaws.

(k) "NERC" means North American Electric Reliability Corporation, the entity certified by FERC as the ERO on July 20, 2006.

(l) "NERC Rules of Procedure" means the Rules of Procedure that are adopted by NERC and approved by FERC.

(m) "PUCT" means the Public Utility Commission of Texas.

(n) "OPUC" means the Texas Office of Public Utility Counsel.

(o) "Originally Elected Independent Director" means a Director approved by the membership on June 2, 2010, in the first election of Texas Reliability Entity, Inc. Independent Directors.

(p) "Regional Entity" means an entity with a Delegation Agreement with NERC, as ERO, including the following organizations, in addition to Texas Reliability Entity: Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst Corporation (RF), Southeastern Electric Reliability Council (SERC), Southwest Power Pool (SPP), and Western Electricity Coordinating Council (WECC).

(q) "Regional Reliability Standard" means a standard for the ERCOT Region that is proposed and approved in accordance with the Texas RE Standards Development Process, as set forth in Exhibit C to the Delegation Agreement, and either, (i) sets more stringent reliability requirements than a national Reliability Standard, or (ii) covers matters not covered by a national Reliability Standard.

(r) "Registered Entity" means an entity that is registered with NERC and listed on the NERC Compliance Registry (available at www.nerc.com).

(s) "Reliability Standard" means a requirement to provide for Reliable Operation of the Bulk-Power System, which is approved by NERC and FERC, pursuant to Section 215 of the Federal Power Act an all amendments thereto. This term includes requirements for the operation of existing Bulk-Power System facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for Reliable Operation of the Bulk Power System.

(t) "Reliable Operation" means operating the elements of the Bulk Power System within equipment and electric system thermal, voltage, and stability limits so that

instability, uncontrolled separation, or cascading failures of the Bulk Power System will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.

(u) "Sector" means a group of Members of the Corporation that are Bulk Power System owners, operators, or users, as defined in Article III, Section 4 of these Bylaws. Each Sector shall constitute a class of Members for purposes of Chapter 22 (Nonprofit Corporations) of the Texas Business Organizations Code.

ARTICLE II.
PURPOSE

Section 1. General Purpose. The purpose of the Corporation is to preserve and enhance reliability in the ERCOT Region. In furtherance of this goal, the Corporation will:

(a) Perform Reliability Standards development, compliance monitoring, compliance enforcement, and other related activities as a Regional Entity, pursuant to 16 U.S.C. §824o, in accordance with the Corporation's Delegation Agreement with NERC;

(b) Carry out other activities as set forth in the Delegation Agreement, the NERC Rules of Procedure, or as otherwise required or requested by NERC, in support of the Delegated Authority, including but not limited to organization registration and certification, reliability assessment and performance analysis, training and education, and situational awareness and infrastructure security; and

(c) Engage in any other lawful act or activity that is not in conflict with the Corporation's duties as a Regional Entity and for which non-profit corporations may be organized under the Texas Business Organizations Code.

Section 2. Non-Profit Corporation. The Corporation is a Texas non-profit corporation.

Section 3. Geographic Area. The Corporation will perform its operations primarily within the ERCOT Region.

ARTICLE III.
MEMBERSHIP

Section 1. Members. The Corporation is a membership corporation. Membership in the Corporation is voluntary and is open only to any entity that is a user, owner or operator of the ERCOT Region Bulk Power System, registers with the Corporation as a Member, maintains its registration in accordance with this Article III, and complies with the other conditions and obligations of membership specified in these Bylaws. All Members must qualify and be registered in one of the Sectors defined in Article III, Section 4. Membership in the Corporation is not a condition to participating in the development or consideration of proposed Regional Standards.

Section 2. Registration as a Member. Any entity that is eligible to be a Member of the Corporation in accordance with Article III, Section 1 may become a Member by completing and submitting to the Corporation a membership registration on a form prescribed by the

Corporation. The Member shall designate one representative and an alternative representative with authority to receive notices, cast votes, and execute waivers and consents on behalf of the Member. The Corporate Secretary shall maintain a current roster of the Members of the Corporation including each Member's designated representative and alternative representative. All Members shall be required to renew their registrations annually. The Corporate Secretary shall remove any Member from the roster that has not submitted a registration renewal by a date established by the Corporation.

Section 3. Obligations and Conditions of Membership.

(a) Members must agree to promote, support, and comply with Reliability Standards, and assist the Corporation in its compliance with the terms and provisions of the Corporation's Delegation Agreement with NERC. Each Member shall agree, in writing, to accept the responsibility to comply with policies of NERC and the Corporation as set forth in their respective certificates of formation, bylaws, rules of procedure, and Reliability Standards, as applicable, as from time to time adopted, approved, or amended.

(b) As an additional condition of membership in the Corporation, each Member shall be required to execute an agreement with the Corporation, in a form to be specified by the Corporation, that such entity will hold all Directors, officers, employees, and agents of the Corporation, as well as volunteers participating in good faith in the activities of the Corporation, harmless for any injury or damage caused by any act or omission of any director, officer, employee, agent, or volunteer in the course of performance of his or her duties on behalf of the Corporation, other than for willful acts of misconduct.

(c) Consistent with applicable laws and regulations, Members must share nonproprietary information at the Corporation's request as necessary for the furtherance of the Corporation's activities and consistent with NERC, PUCT, or any other applicable rules relating to confidentiality.

Section 4. Membership Sectors. Each Member shall elect to be assigned to one of the following membership Sectors:

(a) **System Coordination and Planning**: An entity that is registered with NERC as a Reliability Coordinator (RC), Balancing Authority (BA), Planning Authority (PA), Resource Planner (RP), or Interchange Authority (IA).

(b) **Transmission and Distribution**: An entity that is registered with NERC as a Transmission Owner (TO), Transmission Planner (TP), Transmission Service Provider (TSP), Distribution Provider (DP), and/or Transmission Operator (TOP) and is not a Cooperative or Municipal Utility.

(c) **Cooperative Utility**: An entity that is (a) a corporation organized under Chapter 161 of the Texas Utilities Code or a predecessor statute to Chapter 161 and operating under that chapter; or (b) a corporation organized as an electric cooperative in a state other than Texas that has obtained a certificate of authority to conduct affairs in the State of Texas; or (c) a cooperative association organized under Tex. Rev. Civ. Stat. 1396-50.01 or a predecessor to that statute and operating under that statute and is registered with NERC for at least one reliability function.

(d) **Municipal Utility**: A municipally owned utility as defined in Public Utility Regulatory Act, Tex. Util. Code §11.003 and is registered with NERC for at least one reliability function.

(e) **Generation**: An entity that is registered with NERC as a Generator Owner (GO) or Generator Operator (GOP).

(f) **Load-Serving and Marketing**: An entity that is registered with NERC as a Load Serving Entity (LSE), a Purchasing-Selling Entity, or any newly defined NERC reliability function for demand response.

Section 5. Participation.

(a) There is only one level of Membership, and no company or entity may simultaneously hold more than one Membership.

(b) Members must qualify in and join a Sector.

(c) A Member that is eligible for more than one Sector may join only one Sector and it must be the most appropriate Sector for its business. Any disputes regarding appropriateness of a Member's Sector will be decided by a majority vote of the Board.

(d) A company or entity that is an Affiliate of a Member may hold a separate membership in a different Sector, so long as the legal entities have different NERC Compliance Registry Numbers under which they are currently registered for the applicable NERC reliability function.

(e) A Member must continue to vote in the same Sector for a minimum of the remainder of the membership year in which it becomes a Member or until it is no longer eligible to remain in such Sector, and it must give notice to the Corporate Secretary when it elects or is required to change Sectors.

(f) The Board may review the Sector qualification of any Member and may determine that a Member does not qualify for, and require them to change Sectors.

(g) A Member which is no longer eligible or not in good standing may not vote on any matters that require membership.

Section 6. Membership Fees. Members must pay an annual Membership Fee of $250, to offset the expenses of membership qualification, coordination, and meetings, unless the Board waives the fee for any Member for good cause shown. The Board may agree to change the amount or frequency of the Membership Fee, from time to time, by majority vote.

Section 7. Term of Membership. Membership in the Corporation must be renewed on an annual basis and will only be retained as long as a Member meets its respective qualifications, obligations, and conditions of membership as set forth in these Bylaws. Membership is conditioned on the annual payment of Membership Fees, unless the Membership Fees are waived by the Board for good cause shown, as determined in the Board's sole discretion.

Section 8. Removal. No Member or Member representative may be sanctioned, expelled or suspended and no membership in the Corporation may be terminated or suspended except pursuant to a procedure that is fair and reasonable and is carried out in good faith. The Board may, by resolution, establish a procedure to terminate, expel, suspend, or

sanction a Member following notice to the Member and exercise of appropriate due process procedures and a determination by the Board in its sole discretion that in its judgment the Member has violated its obligations and responsibilities to the Corporation. In the event that the Board does not adopt procedures, the following procedures shall apply:

(a) Written notice. Written notice of intent to terminate, expel, suspend or sanction a Member shall be delivered at least twenty (20) days in advance of the date when a hearing will be held to determine whether the Member shall be expelled, suspended, terminated or sanctioned. Such notice shall set forth the reasons therefore. Said notice must be given by facsimile (receipt confirmed), e-mail (receipt confirmed) or first class or certified mail sent to the last address of the Member to be expelled, suspended, terminated or sanctioned, as shown in the Corporation's records.

(b) Hearing. An opportunity shall be provided for the Member receiving such notice to be heard by the Board at the hearing, orally and in writing. The Member shall be entitled to have counsel present, and to participate in the hearing, at its own expense, and to present and cross-examine any witnesses.

(c) Liability. A Member which has been sanctioned, expelled, terminated or suspended shall remain liable to the Corporation for fees as a result of obligations incurred or commitments made prior to sanction, expulsion, termination or suspension.

(d) Challenges. Any request for a proceeding challenging an expulsion, suspension, sanction or termination, including a proceeding in which defective notice is alleged, may be submitted to the Board in writing within one year after the effective date of the expulsion, suspension, sanction or termination. If the Board determines to hear such challenge, it shall notify the Member and such proceeding will be subject to the hearing requirements described in subsection (b) above of this Section 8.

Section 9. Resignation. Any other provision of these Bylaws notwithstanding, any Member may withdraw from participation in the activities of the Corporation at any time upon written notice to the chief executive officer or president of the Corporation, whereupon it shall cease to be a Member, and its representatives shall cease to be entitled or obligated to participate in the activities of the Board or any activities requiring membership.

Section 10. Reinstatement. A former Member may submit a written request for reinstatement of Membership. The Board will reinstate the Membership unless the entity does not meet the Membership qualifications set forth in these Bylaws.

ARTICLE IV.
BOARD OF DIRECTORS

Section 1. Board of Directors. The business and affairs of the Corporation shall be managed by the Board. The Board shall consist of (i) four (4) Independent Directors who are nominated and elected in accordance with the requirements and procedures specified in this Article IV (the "Independent Directors"); (ii) the Chairman of the PUCT or another PUCT Commissioner designated by the Chairman, as an *ex officio* non-voting member; (iii) Texas Public Counsel, from OPUC (or another employee of OPUC designated by Texas Public Counsel), as an *ex officio* non-voting member, representing the interests of residential and small commercial electricity consumers; (iv) the CEO of the Corporation as a voting member (the "Management Director"); (v) the chair of the Member Representatives Committee as a voting member; and (vi) the vice chair of the Member Representatives Committee as a voting member. The Directors who

are the chair and vice chair of the Member Representatives Committee will be collectively referred to herein as "Affiliated Directors." Each Director, including the Affiliated Directors and excluding the non-voting members of the Board, shall have one (1) vote on any matter brought before the Board for a vote. All Directors are expected to serve the public interest and to represent the reliability concerns of the entire ERCOT Region Bulk Power System.

Section 2. Independent Directors. The Independent Directors shall be elected, shall have the qualifications specified, and shall serve in the manner provided in this Section.

(a) Qualifications:

(1) Experience in one or more of these fields: senior corporate leadership; professional disciplines of finance, accounting, engineering, bulk power systems, or law; regulation of utilities; and/or risk management.

(2) Independence of any NERC Registered Entity. Requirements of independence include but are not limited to the following:

(i) Independent Directors and the spouse, mother, father, sibling, or dependent, and any spouse of mother, father, or sibling and including any step and adoptive parents, siblings or children, and household members of Independent Directors and their spouses shall not have current or recent status (within the last two years) as a director, officer, or employee of an ERCOT Region NERC Registered Entity.

(ii) Independent Directors and immediate family (any spouse or dependent) and household members of Independent Directors shall not have current status as a director, officer, or employee of a non-ERCOT Region NERC Registered Entity.

(iii) Independent Directors and immediate family and household members of Independent Directors shall not have direct business relationships, other than retail customer relationships, with any NERC Registered Entity.

(iv) Independent Directors and immediate family and household members of Independent Directors shall not own stocks or bonds of NERC Registered Entities or their affiliates. To the extent that an Independent Director or his or her spouse, dependent child, or any other household member owns stocks or bonds of NERC Registered Entities, these must be divested or placed in a blind trust prior to being seated on the Board. Ownership in broadly diversified mutual funds or similar funds, which may include stocks or bonds of NERC Registered Entities or their affiliates, is not prohibited.

(v) Independent Directors shall not have any relationship that would interfere with the exercise of independent judgment in carrying out the responsibilities of a Board member, including the Delegated Authority.

(vi) Other criteria as approved by the Board.

(b) Term. The term for Independent Directors shall be staggered three year terms. An Independent Director may be elected for up to three consecutive terms. For the Originally Elected Independent Directors, two positions will have three-year terms, one position

will have a two-year term, and one position will have a one-year term, and these terms shall not be counted for purposes of term limits. The term for the Affiliated Directors who are chair and vice chair of the Member Representatives Committee shall be two years, and the terms of the *ex officio* Directors will not expire. If an Independent Director is elected to fill an unexpired term in the event of a vacancy, that term shall not be counted for purposes of term limits.

(c) Selection.

(1) The Board shall appoint, on an annual basis, or more frequently if needed in the event of a special election pursuant to this subsection, a nominating committee (the "Nominating Committee") to recommend candidates (i) to succeed the Independent Directors whose terms expire during the current year and (ii) to serve the remainder of the term of any Independent Director who ceased to serve as a Director subsequent to the last annual election of Directors. The Nominating Committee shall consist of two (2) Independent Directors whose terms do not expire during the current year and are not seeking re-election and one (1) Affiliated Director. The PUCT Chairman (or the PUCT Commissioner designated by the Chairman) may choose to participate on the Nominating Committee. The Board Chair shall appoint the Chair of the Nominating Committee. The Nominating Committee may retain an executive search firm to locate and present candidates with the required qualifications, as set forth in Article IV, Section 2(a). Meetings of the Nominating Committee are not required to be publicly posted.

(2) The Nominating Committee shall select and nominate, by at least a two-thirds majority, qualified candidate(s) to present to the Membership for its approval. The Nominating Committee shall strive to ensure that the Board as a whole reflects expertise in the areas of technical electric operations and reliability, legal, senior corporate leadership, financial, risk management, and regulatory matters, and familiarity with regional system operation issues in the ERCOT Region.

(3) The Membership shall vote by Sector as described in Article V in favor or against the proposed Independent Director(s). A proposed Independent Director who is approved by a majority of the Sectors shall become an Independent Director.

(d) Director Voting Weights. All voting Directors shall have a single vote each.

(e) Alternates and Proxies. Independent Directors may designate another Independent Director as a proxy if unable to attend a Board meeting. Ex officio Directors may designate a selected proxy or an alternate representative who may attend meetings in the absence of such Director. The chair and vice chair of the Member Representatives Committee may designate each other or may designate an Independent Director as their proxy if unable to attend a Board meeting.

Section 3. Appointment of Management Director. The president and chief executive officer (CEO) of the Corporation shall serve as the Management Director of the Corporation, effective as of the date of his or her appointment by the Board as CEO of the Corporation in accordance with these Bylaws, to serve until such time that he or she ceases to hold the position of CEO. No action of the Members of the Corporation shall be required in connection with the appointment of the CEO as the Management Director of the Corporation.

Section 4. Chair and Vice Chair. Annually, the Board shall elect from the Board's membership, by resolution of the Board, a Chair and a Vice Chair. The Chair and Vice Chair shall each be one of the Independent Directors.

Section 5. Vacancies and Removal.

(a) Should any vacancy on the Board arise from the death, resignation, retirement, disqualification, or removal from office of any Director, or from any other cause, such vacancy shall be filled as follows:

(1) For an Independent Director, by the election of a new Independent Director at the next annual election of Directors to fill the remainder, if any, of the term of the departed Independent Director; provided, that the Board by resolution may in its discretion call a special election to fill any such vacancy for the remainder, if any, of the term of the departed Independent Director.

(2) For the Management Director, by the appointment of a new CEO or interim CEO to fill the vacancy.

(3) For an ex officio Director, by the appointment of a new PUCT Chair or Texas Public Counsel by whomever had the right to appoint such Director.

(4) For an Affiliated Director, by the election of a new chair or vice chair, as applicable, by the Member Representative Committee.

(b) A Director may be removed with or without cause at any time by whomever had the right to appoint such Director (for ex officio Directors), or for the elected Independent Directors, by an affirmative vote of sixty percent (60%) of the Members. In addition, the Board may remove any voting Director for cause, upon at least seventy-five percent (75%) affirmative votes of the eligible, remaining voting Directors. The right to elect Directors may not be assigned, sold, pledged or transferred in any manner.

Section 6. Committees of the Board. The Board shall by resolution create and appoint all committees of the Board as the Board deems necessary to perform its responsibilities. All committees of the Board shall have such duties as are prescribed and delegated by the Board. Committees to which any of the authority of the Board to manage the Corporation is delegated must have at least two Directors, and a majority of the members of the committee must be Directors.

ARTICLE V.
MEETINGS OF MEMBERS OF THE CORPORATION

Section 1. Annual and Other Meetings of Members.

(a) An annual meeting of the Members to elect Directors, announce election results from electronic elections, and conduct such other business as may come before the meeting, shall be held in December each year. The failure to hold an annual meeting in accordance with these bylaws shall not affect the validity of a corporate action.

(b) Meetings of Members of the Corporation may be called for any purpose or purposes by resolution of the Board, by the chair of the Board, the CEO or the Corporate Secretary, or by a number of Members constituting at least ten (10) percent of all Members on

the roster of Members maintained by the Corporate Secretary, which number shall include Members in at least three (3) of the Sectors. Meetings of Members shall be held at the principal office of the Corporation or at such other place fixed by the Board as shall be specified in the notice of meeting. Meetings shall be called upon written notice of the time, date, place, and purposes of the meeting given to all Members on the roster of Members maintained by the Corporate Secretary not less than ten (10) nor more than sixty (60) days prior to the date of the meeting. Only Members in good standing with the Corporation, as determined by the Board, have the right to vote at any meeting of the Members. Further, if at any point a Member no longer meets the qualifications for the Sector of which it is a member, the Entity may immediately elect to become a member in any Sector for which it does qualify.

Section 2. Quorum and Voting Requirements for Meetings of Members.

(a) At any meeting of the Members of the Corporation, attendance in person or by proxy by a majority of the Members in each of at least two-thirds of the Sectors on the roster of Members maintained by the Corporate Secretary shall constitute a quorum.

(b) Except as otherwise expressly provided in the Corporation's Certificate of Formation, these Bylaws, or applicable law, Members shall vote by Sector and each Sector shall have one vote.

(c) To the extent practicable, membership votes will be conducted electronically and prior to annual membership meetings.

(d) Except as otherwise expressly provided in the Corporation's Certificate of Formation, these Bylaws or applicable law, actions by the Members of the Corporation shall be approved upon receipt of the affirmative vote of a majority of the Sectors of the Corporation at (1) a meeting at which a quorum is present, in person or by proxy, or (2) an electronic vote which has participation by a quorum. Each Sector's vote shall be determined by the affirmative vote of a majority of the members of the Sector voting at the meeting or in the electronic election.

Section 3. Waivers of Notice of Meetings of Members and Member Meeting Adjournments. Notice of a meeting of Members need not be given to any Member who waives notice, either electronically or in writing, in person or by proxy, whether before, during, or after the meeting. The attendance of any Member at a meeting, in person or by proxy, without protesting prior to the conclusion of the meeting the lack of proper notice of such meeting, shall constitute a waiver of notice of the meeting by such Member. When any meeting of Members is adjourned to another time or place, it shall not be necessary to give notice of the adjourned meeting if the time and place to which the meeting is adjourned are announced at the meeting at which the adjournment is taken, and if at the adjourned meeting only such business is transacted as might have been transacted at the original meeting.

Section 4. Action Without a Meeting of Members. Any action, required or permitted to be taken at a meeting of Members, may be taken without a meeting if the proposed action is posted to all Members (via direct email or email to an email distribution list to which Members may subscribe and by posting on the Corporation website) and consented to in writing by the minimum number of Members that would be required to approve the action at a meeting of the Members at which all Members were present. The voting in such a circumstance shall be performed in writing, including via email or other electronic means. The Members shall receive written notice of the results within ten (10) days of the action vote, and all written responses of the Members shall be filed with the Corporate records. The results of such voting will be posted on the Corporation's website.

Section 5. Meetings of the Members to be Open. Notice to the public of the dates, places, and times of meetings of the Members, and all non-confidential material provided to the Members, shall be posted on the Corporation's website at approximately the same time that notice is given to the Members. Meetings of the Members shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided, that the meeting may be held in or adjourned to closed session to discuss matters of a confidential nature, including but not limited to compliance and enforcement matters, personnel matters, litigation, or commercially sensitive or critical infrastructure information of the Corporation or any other entity. The results of any action taken without a meeting, as described above, will be posted on the Corporation's website.

ARTICLE VI.
MEETINGS OF THE BOARD OF DIRECTORS

Section 1. Regular Meetings of the Board. Regular meetings of the Board shall be held at least quarterly. By resolution adopted at any meeting of the Board, the Board may provide for additional regular meetings that may be held as needed.

Section 2. Special Meetings of the Board. Special meetings of the Board for any purpose or purposes may be called at any time by the chair or by any two Directors. Such meetings may be held upon notice given to all Directors not less than three (3) days prior to the date of the meeting. Such notice shall specify the time, date, place, and purpose or purposes of the meeting and may be given by telephone, email or other electronic media, or by express delivery.

Section 3. Quorum and Voting Requirements for Meetings of the Board. Unless otherwise expressly provided in the Corporation's Certificate of Formation, these Bylaws or applicable law, (i) the quorum necessary for the transaction of business at meetings of the Board shall be a majority of the voting Directors in person or by proxy and at least three Independent Directors, and (ii) actions by the Board shall be deemed approved upon receipt of the affirmative vote of a majority of the Directors present and voting in person (by means of any communications system by which all persons participating in the meeting are able to hear each other) or by proxy at a meeting at which a quorum is present but in no case less than four votes.

Section 4. Meetings of the Board to be Open. Notice to the public of the dates, places, and times of meetings of the Board, and all non-confidential material provided to the Board, shall be posted on the Corporation's website at approximately the same time that notice or such material is given to the Directors and at least five (5) business days prior to the scheduled meeting. Meetings of the Board shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided, that the Board may meet in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to compliance and enforcement matters, personnel matters, litigation, or commercially sensitive or critical infrastructure information of the Corporation or any other entity. Any or all of the Directors or members of a Board committee, may participate in a meeting of the Board, or a meeting of a committee, in person or by proxy, by means of any communications system by which all persons participating in the meeting are able to hear each other.

Section 5. Waivers of Notice of Board Meetings and Board Meeting Adjournments. Notice of a board meeting need not be given to any Director who signs, or sends an email confirming a waiver of notice, in person or by proxy, whether before, during, or after the meeting, or who attends the meeting without protesting the lack of notice of such meeting prior to the conclusion of the meeting. Notice of an adjourned board meeting need not be given if the time

and place to which the meeting is adjourned are announced at the meeting at which the adjournment is taken and if the period of adjournment does not exceed ten (10) days.

Section 6. Action Without a Meeting. Any action required or permitted to be taken at a meeting of the Board, or of any committee thereof, may be taken by the Board or by the committee without a meeting if the action is consented to in writing by the number of Directors or members of the committee, as the case may be, entitled to vote on the action that would be required to approve the action at a meeting of the Board or committee with all members of the Board or committee present. The call for action without a meeting of the Board may be initiated by the chair or by any two voting Directors. Notice of the proposed call for action without a meeting, and all non-confidential material provided to the Board in connection with the call for action without a meeting, shall be posted on the Corporation's website and shall be sent via email to an email distribution list to which Members and the public may subscribe at approximately the same time notice of the call for action without a meeting or such material is provided to the Board. The call for action without a meeting of a committee of the Board may be initiated by the chair of the committee or by any two members of the committee. The Directors or members of the committee shall receive written notice of the results of such action within seven (7) days of the action vote. All written responses of the Directors shall be filed with the minutes of the Corporation, and all written responses of members of a committee shall be filed with the minutes of such committee.

Section 7. Emergency Meetings. The Board may meet on urgent matters with not less than two (2) hours' public notice, as necessary or appropriate for emergency conditions threatening health or safety or a reasonably unforeseen situation.

ARTICLE VII.
OFFICERS

Section 1. Selection of Officers. The Board shall elect a CEO and shall ratify the selection of the officers of the Corporation (collectively, the "Officers"). The Management Director shall not participate in votes electing or ratifying Officers. The Corporation shall maintain a list of current Officers ratified by the Board. The duties and authority of the Officers shall be determined from time to time by the Board. Subject to any such determination, the Officers shall have the following duties and authority:

Section 2. Chief Executive Officer ("CEO"). The CEO shall be the chief executive officer of the Corporation. He or she shall be responsible for the day-to-day ongoing activities of the Corporation and shall have such other duties as may be delegated or assigned to him or her by the chair. The CEO may enter into and execute in the name of the Corporation contracts or other instruments not in the regular course of business that are authorized, either generally or specifically, by the Board.

Section 3. Corporate Secretary. The secretary shall maintain the roster of Members of the Corporation, shall cause notices of all meetings to be served as prescribed in these Bylaws, shall keep or cause to be kept the minutes of all meetings of the Members and the Board, and shall have charge of the seal of the Corporation. The secretary shall perform such other duties and possess such other powers as are incident to his or her office or as shall be assigned to him or her by the CEO. The CEO may select an Assistant Corporate Secretary at his or her discretion. The Assistant Corporate Secretary is not an Officer of the Corporation.

Section 4. Chief Financial Officer. A Chief Financial Officer shall have custody of the funds and securities of the Corporation, shall keep or cause to be kept regular books of account for the Corporation and shall have the duties normally assigned to a treasurer of a corporation. The Chief Financial officer shall perform such other duties and possess such other powers as are incident to his or her office or as shall be assigned to him or her by the CEO.

Section 5. Other Officers. The CEO may select such other Officers as he or she deems appropriate, subject to ratification by the Board. Any such Officer shall perform such other duties and possess such powers as are incident to his or her office or as shall be assigned to him or her by the CEO.

ARTICLE VIII.
RELIABILITY STANDARDS COMMITTEE

Section 1. Requirement. The Corporation shall have a Reliability Standards Committee, which shall operate in accordance with the Standards Development Process as set forth in Exhibit C to the Delegation Agreement with NERC and approved by FERC. The chair and vice chair of the Standards Committee must be accepted or approved by the Board, in accordance with said Exhibit C.

ARTICLE IX.
MEMBER REPRESENTATIVES COMMITTEE

Section 1. Purpose of Member Representatives Committee. The Corporation shall have a "Member Representatives Committee" that shall provide advice and recommendations to the Board with respect to: annual budgets, business plans and funding mechanisms of the Corporation; other matters relevant to reliability of the ERCOT Bulk Power System; and other matters pertinent to the purpose and operations of the Corporation. The Member Representatives Committee shall provide its advice and recommendation to the Board through its chair and the vice chair, who also serve as the Affiliated Directors on the Board. The Member Representatives Committee may create subcommittees, task forces, or working groups ("subcommittees") as it deems appropriate to study or discuss selected technical or compliance matters and to make recommendations to the Board as requested or required by the Board or as deemed appropriate to its purpose by the Member Representatives Committee. Because it is elected by the Members of the Corporation and not appointed by the Board, the Member Representatives Committee shall not be a standing committee of the Board of Directors of the Corporation, but is authorized to provide advice and recommendations directly to the Board, through its elected chair and vice chair.

Section 2. Composition of the Member Representatives Committee. The Member Representatives Committee shall consist of two representatives from each Sector to serve two-year terms and will select a chair and vice chair for the Member Representatives Committee to serve two-year terms. The representatives of each Sector shall be officers, employees, or directors of Members in that Sector (or the Member's parent, subsidiary, or other Affiliate); provided however, except for a Sector that has only one Member, only one officer, employee, or director of a Member in a Sector (or the Member's parent, subsidiary, or other Affiliate) may be a representative from that Sector. The Board may by resolution create additional non-voting positions on the Member Representatives Committee on its own initiative or at the written request of any group of Members of the Corporation that believes its interests are not adequately represented on the Member Representatives Committee. There shall be no limit on the number of terms that an officer, employee, or director of a Member (or the Member's parent, subsidiary, or other Affiliate), may serve on the Member Representatives Committee.

Section 3. Election of Representatives of the Member Representatives Committee. Unless a Sector adopts an alternative election procedure, the election of representatives from each Sector to the Member Representatives Committee, and any election to fill a vacancy, shall be conducted in accordance with the following process, which shall be administered by the officers of the Corporation.

(a) During the period beginning no more than ninety (90) days and ending no less than fifteen (15) days prior to an annual meeting, or beginning no more than forty-five (45) days and ending no less than fifteen (15) days prior to a special election to fill a vacancy on the Member Representatives Committee, nominations may be submitted for candidates for election to the Member Representatives Committee. A nominee for election as a Sector representative must be an officer, employee, or director of a Member in that Sector (or the Member's parent, subsidiary, or other Affiliate). No more than one nominee who is an officer, employee, or director of a Member (or the Member's parent, subsidiary, or other Affiliate) may stand for election in any single Sector; if more than one officer, employee, or director of a Member (or the Member's parent, subsidiary, or other Affiliate) is nominated for election from a Sector, the Member shall designate which such nominee shall stand for election. The election of representatives shall be conducted over a period of ten (10) days using an electronic process approved by the Corporate Secretary.

(b) Each Member in a Sector shall have one vote for each Representative to be elected from the Sector in that election and may cast no more than one vote for any nominee. The nominee receiving the highest number of votes in each Sector shall be elected to one Representative position to be filled from that Sector and the nominee receiving the second highest number of votes shall be elected as the second Representative position for that Sector. To be elected on the first ballot, a nominee must receive a number of votes equal to a simple majority of the Members in the Sector casting votes in the election. If no nominee in a Sector receives a simple majority of votes cast in the first ballot, a second ballot shall be conducted which shall be limited to the number of candidates receiving the three (3) highest vote totals on the first ballot. The nominees receiving the two highest totals of votes on the second ballot shall be elected to the Representative positions for the Sector.

(c) A Sector may adopt an alternative procedure to the foregoing to nominate and elect its Representatives to the Member Representatives Committee if the alternative procedure is approved by vote of at least two-thirds of the Members in the Sector, provided, however that any alternative procedure may be reviewed and disapproved by the Board.

(d) A Sector may elect an Alternate to serve in place and at the convenience of the Sector's Member Representatives Committee Representative(s) in the event a Member Representatives Committee Representative cannot attend a Member Representatives Committee meeting.

Section 4. Chair and Vice Chair of the Member Representatives Committee. After the selection of its Representatives, the Member Representatives Committee shall select a chair and vice chair from among its voting Representatives by majority vote to serve during the upcoming two-year term and be the Affiliated Directors on the Board. The selected chair and vice chair may not be representatives of the same Sector and may not concurrently serve on the Board of ERCOT ISO. The Board shall be notified of the selection of the chair and vice chair, but the selection will not be subject to approval of the Board. The chair is responsible for ensuring that minutes of the meetings are properly maintained and made available to the public, but the chair may delegate this responsibility to the vice chair or to another Representative of the Member Representatives Committee who may be designated as secretary of the Member Representatives Committee.

Section 5. Vacancies on the Member Representatives Committee. In the event that any Representative of the Member Representatives Committee ceases to serve as a Representative of the Member Representatives Committee as a result of his or her death, resignation, retirement, disqualification, removal, or other cause, the Members in the Sector of which such Representative was a representative shall elect, as soon thereafter as reasonably practicable, and in accordance with the procedures in this Article IX, a new Representative to replace the Representative of the Member Representatives Committee who ceased to serve. For those Sectors that have elected an Alternate, the Alternate will fill a vacancy left by the Sector's Member Representative and a new Alternate will be elected by the Sector.

Section 6. Meetings of the Member Representatives Committee. The Member Representatives Committee will plan and hold quarterly meetings, at a time and place determined by the Member Representatives Committee, normally shortly before the regular meetings of the Board, and posted on the Corporation's website. Except for closed session meetings specifically allowed by this Section, all meetings shall be open to the public. The Member Representatives Committee shall adopt such procedural rules as are needed to operate in accordance with its purpose and will include procedures for coordinating with employees of the Corporation who provide administrative support, as set forth in subsection 6(c), below.

(a) Notice to the public of the dates, places, and times of meetings of the Member Representatives Committee and any subcommittees thereof, and all non-confidential material provided to the Representatives on the Member Representatives Committee or any subcommittees thereof, shall be posted on the Corporation's website at approximately the same time that notice or such material is given to the Member Representatives Committee, which will normally be at least five (5) business days prior to the scheduled meeting. Meetings of the Member Representatives Committee shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided, that the Member Representatives Committee may meet in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to confidential planning information, critical infrastructure information, or commercially sensitive information of the Corporation or any other entity. Any or all Representatives of, and any other participants in, the Member Representatives Committee may participate in a meeting of the Member Representatives Committee by means of a communications system by which all persons participating in the meeting are able to hear each other.

(b) Special meetings may be called for any purpose or purposes by the chair of the Member Representatives Committee or by any three (3) Representatives of the Member Representatives Committee, which number shall include representatives from at least three Sectors, and require notice given to all Representatives of the Member Representatives Committee not less than seven (7) days prior to the date of the meeting. Such notice shall specify the time, date, place, and purpose or purposes of the meeting and may be given by telephone, facsimile, or other electronic media, or by express delivery.

(c) The Member Representatives Committee shall effectively coordinate with the employees of the Corporation and adopt procedural rules for the voting for Representatives, scheduling of meetings, and public posting of required meeting information and minutes. The chair or vice chair of the Member Representatives Committee shall provide all meeting agendas, material, minutes and other information required or desired to be posted on the Corporation's website to appropriate Corporation employees at least one business day prior to the time such information should be posted.

Section 7. Waivers of Notice of Meetings of the Member Representative Committee and Meeting Adjournments. Notice of a meeting of the Member Representatives Committee need not be given to any member of the Member Representatives Committee who waives notice electronically or otherwise in writing, in person or by proxy, whether before or after the meeting, or who attends the meeting without protesting, prior to the conclusion of the meeting, the lack of notice of such meeting. Notice of an adjourned meeting of the Member Representatives Committee need not be given if the time and place to which the meeting is adjourned are announced at the meeting at which the adjournment is taken and if the period of adjournment does not exceed ten (10) days.

Section 8. Quorums and Voting for Meetings of the Member Representatives Committee. The quorum necessary for the transaction of business at meetings of the Member Representatives Committee shall be the presence, in person or by proxy, of two-thirds of the voting Representatives on the Member Representatives Committee entitled to attend. Each voting member of the Member Representatives Committee shall have one (1) vote on any matter coming before the Member Representatives Committee that requires a vote. Except as otherwise expressly provided in the Corporation's Certificate of Formation, these Bylaws or applicable law, actions by members of the Member Representatives Committee shall be approved upon receipt of the affirmative vote of a majority of the voting members of the Member Representatives Committee present (by means of any communications system by which all persons participating in the meeting are able to hear each other) and voting at any meeting at which a quorum is present.

Section 9. Alternates and Proxies. Member Representatives may designate another Member Representative or an employee of the Member Representative's organization (or the Member's parent, subsidiary, or other Affiliate) as a proxy if both the Member Representative and the Sector Alternate are unable to attend a Member Representatives Committee meeting. A member of the Member Representatives Committee may give a proxy only to a person who is an officer, employee, or director of a Member, registered in the same Sector (or the Member's parent, subsidiary, or other Affiliate).

Section 10. Other Procedures of the Member Representatives Committee. Except as to any matter as to which the procedure to be followed by the Member Representatives Committee is expressly set forth in these Bylaws, the Member Representatives Committee may adopt such additional procedures, not inconsistent with these Bylaws, as it deems appropriate, subject to review and disapproval by the Board.

ARTICLE X.
OTHER COMMITTEES AND SUBCOMMITTEES

Section 1. Committees of the Corporation. In addition to those committees specified by these Bylaws, to which the Board shall appoint members in accordance with the requirements of these Bylaws, the Board may by resolution create standing committees of the Corporation; and may in addition by resolution appoint the members of such committees, subcommittees, task forces and Sector-specific forums as the Board deems necessary or desirable to carry out the purposes of the Corporation. The Board shall appoint members to such standing committees and other committees of the Corporation that are representative of Members, other interested parties, and the public, that provide for balanced decision-making and that include persons with sufficient technical knowledge and experience. All committees, subcommittees, task forces and Sector-specific forums shall have such scope and duties, not inconsistent with law, as are specified in these Bylaws and the Rules of Procedure of the Corporation or otherwise determined by the Board.

ARTICLE XI.
BUDGETS AND FUNDING

Section 1. Compensation of the Board and Member Representatives Committee. The Board shall have the right to fix from time to time, by resolution adopted by a majority of the Directors including a majority of the Independent Directors then serving as Directors, the amount of the annual retainer fee or other compensation to be paid to the Independent Directors for their services to the Corporation, including any fees to be paid for each meeting of the Board or any Board committee attended by an Independent Director. The Board will evaluate the fee or other compensation at least every three years, to ensure that Director compensation is appropriate. No compensation shall be paid to any Management Director, Affiliated Director, or *ex officio* Director for his or her services on the Board, other than the compensation paid to the Management Director for services as CEO of the Corporation. No compensation shall be paid by the Corporation to any member of the Member Representatives Committee for his or her services on the Member Representatives Committee. Independent Directors shall be entitled to be reimbursed their reasonable out-of-pocket expenditures for attending meetings and conducting the business of the Corporation.

Section 2. Preparation and Adoption of Annual Budget, Business Plan, and Funding Mechanism. The Board shall require the CEO to prepare for Board approval an annual business plan and budget for the administrative and other expenses of the Corporation, including the expenditures for the fiscal year for any material special projects undertaken by the Corporation and reasonable and proper reserves and provisions for contingencies, in accordance with all NERC and FERC requirements. The annual business plan, budget and funding mechanism of the Corporation shall be for a fiscal year commencing on January 1 and ending on December 31. Each annual business plan, budget, and funding mechanism shall be approved by the Board at a regular meeting or a special meeting of the Board duly called for that purpose. The Board shall approve each annual business plan, budget, and funding mechanism at a time that allows for timely submittal of the approved annual business plan, budget, and funding mechanism to the applicable regulatory authorities.

Section 3. Comments During Preparation of Annual Business Plan and Budget. In preparing the annual business plan and budget, the Board shall require that the CEO post a draft business plan and budget for review and comment by the Members of the Corporation, the Member Representatives Committee, and the standing committees of the Corporation for at least five (5) business days prior to the date of the meeting of the Board at which the annual business plan and budget is to be adopted.

Section 4. Modified or Supplemental Budgets. During the course of a fiscal year, the Board may modify any approved budget or develop and approve a supplemental budget if determined by the Board to be necessary due to such factors as a shortfall in revenues of the Corporation from projected levels, incurred or anticipated expenditures, duties, or new projects not provided for in the annual budget, or such other factors as in the judgment of the Board warrant modification of the budget for the fiscal year or development of a supplemental budget. In preparing a modified or supplemental budget, the Board shall follow the provisions of this Article XI, Section 4 to the extent practicable in the judgment of the Board in light of the urgency of the circumstances necessitating preparation and approval of the modified or supplemental budget. Each modified or supplemental budget shall be approved by the Board at a regular meeting or a special meeting of the Board duly called for that purpose.

Section 5. Submission of Annual Business Plans and Budgets to the Regulatory Authorities. Each annual budget, annual business plan, and annual, modified, or

supplemental budget approved by the Board shall be submitted by the Corporation to the ERO and any applicable regulatory authorities for approval in accordance with its regulations, and shall not be effective until approved by the applicable regulatory authorities. If ordered to modify or remand an annual budget, business plan, or annual, modified, or supplemental funding mechanism, the Board shall promptly following such order adopt such modifications to the business plan, budget , or funding mechanism as are required or directed by the order of the ERO and any applicable regulatory authority.

ARTICLE XII.
AMENDMENTS TO THE BYLAWS

Section 1. Amendments to the Bylaws. These Bylaws may be altered, amended, or repealed by action of the Membership, as set forth below. Any alteration, amendment, repeal or adoption of Bylaws shall be subject to any applicable requirements for filing with or approval by the ERO or any other applicable regulatory authority. These Bylaws may be altered, amended, or repealed as follows:

(a) Any Director or Member suggesting amendments to these Bylaws must submit a proposal of the amendment, including any necessary supporting documents, to the CEO.

(b) The CEO shall place the proposal on the agenda for a Board meeting in the time and manner prescribed by the Board and within ninety-five (95) days of the request.

(c) If the proposal is approved by an act of the Board as set forth in Article VI, Section 3, the Board shall place the proposal on the agenda of the next Annual Meeting of the Corporate Members unless the Board in its discretion calls a Special Meeting of the Corporate Members to vote on the proposal or determines to seek Membership approval without a meeting as provided in Article V, Section 4.

(d) If the proposal is not approved by the Board, the Members of the Corporation may call a meeting, pursuant to Article V, Section 1(b), for the purpose of voting on a proposal not approved by the Board. Any such proposal must be approved by a vote of five of the six Sectors at a meeting of Members called for that purpose or by written consent of five of the Sectors, where the number of votes for and against the proposed alteration, amendment, repeal or adoption of Bylaws shall be determined in accordance with Article V, Section 2.

ARTICLE XIII.
INDEMNIFICATION; PROCEDURE; DISSOLUTION

Section 1. Indemnification. The Corporation shall indemnify each person who at any time shall serve, or shall have served, as an officer, Director, employee, or other corporate agent of the Corporation, is or was serving at its request as a director, officer, partner, venturer, proprietor, employee, agent or similar functionary of another foreign or domestic corporation, partnership, joint venture, sole proprietorship, trust, employee benefit plan or other enterprise ("Indemnified Parties"), to the full extent from time to time permitted by the Texas Business Organizations Code and other applicable law. Such right of indemnification shall inure to the benefit of the legal representative of any such Indemnified Party. The foregoing indemnification shall be in addition to, and not in restriction or limitation of, any privilege or power that the Corporation may have with respect to the indemnification or reimbursement of its Indemnified Parties. The Corporation shall also pay or advance reasonable expenses incurred by an Indemnified Party in connection with a proceeding in advance of the final disposition of the

proceeding upon receipt of a written affirmation by the Indemnified Party of a good faith belief that the standard of conduct necessary for indemnification under this Article XIII and the Texas Business Organizations Code has been met and a written undertaking by or on behalf of the officer, Director, or other corporate agent to repay the amount if it shall be ultimately determined that the Indemnified Party was not entitled to be indemnified by the Corporation.

Section 2. Parliamentary Rules. In the absence of and to the extent not inconsistent with specific provisions in these Bylaws, meetings or other actions pursuant to these Bylaws shall be governed by procedures that the Board may, from time to time, establish by resolution.

Section 3. Dissolution. Upon dissolution of the Corporation, in accordance with the Certificate of Formation, the remaining assets of the Corporation after payment of debts shall be distributed in the manner determined by the Board, provided that, (i) no part of the assets shall be distributed to any Director of the Corporation, and (ii) the distribution of assets shall be consistent with the requirements of Section 501(c)(3) of the United States Internal Revenue Code of 1954.

ARTICLE XIV.
CONFLICTS OF INTEREST

Section 1. Conflicts of Interest.

(a) Each Director shall have an affirmative duty to disclose to the Board or committee (as the case may be) any actual or potential conflicts of interest of the Director that arise during his or her tenure as a Director where, and to the extent that, such conflicts or potential conflicts directly or indirectly affect any matter that comes before the Board. A Director with a direct or potentially conflicting interest in a matter shall recuse himself from deliberations and actions on the matter in which the conflict arises and shall abstain on any vote on the matter and not otherwise participate in a decision on the matter. Any disclosure of a potential conflict of interest by a Director shall be noted in the minutes of the Board meeting at which the direct interest is disclosed. Mere attendance at the meeting, without participating in discussion of the issue raising the potential conflict, shall not constitute participation.

(b) The Corporation may not make any loan to a Director, committee member or officer of the Corporation. A Member, Director, officer, or committee member of the Corporation may not lend money to, or otherwise transact business with, the Corporation except as otherwise provided by these Bylaws, the Certificate of Formation, and applicable law. A related party transacting business with the Corporation has the same rights and obligations relating to those matters as other persons transacting business with the Corporation, provided the related party nature of the transaction is known to the Board. The Corporation may not borrow money from, or otherwise transact business with, a Member, Director, officer, or committee member of the Corporation unless the transaction is described fully in a legally binding instrument, is in the Corporation's best interests, and is on terms no less favorable to the Corporation than could be obtained in an arms-length transaction. The Corporation may not borrow money from, or otherwise transact business with, a Member, Director, officer, or committee member of the Corporation without full disclosure of all relevant facts and without the Board's approval, not including the vote of any person having a personal interest in the transaction.

Section 2. Prohibited Acts. No Member, Director, officer, or committee member of the Corporation may do any of the below-listed prohibited acts. Engaging in these

prohibited acts may lead to sanction, suspension, expulsion or termination after a hearing as described in these Bylaws. The prohibited acts include the following:

(a) Do any act in violation of these Bylaws.

(b) Do any act in violation of a binding obligation of the Corporation except with the Board's prior approval.

(c) Do any act with the intention of harming the Corporation or any of its operations.

(d) Receive an improper personal benefit from the operation of the Corporation.

(e) Use the Corporation's assets, directly or indirectly, for any purpose other than carrying on the Corporation's business.

(f) Wrongfully transfer or dispose of Corporation property, including intangible property such as goodwill.

(g) Use the Corporation's name (or any substantially similar name) or any trademark or trade name adopted by the Corporation, except on behalf of Corporation in the ordinary course of its business or as a reference to the Corporation or its region.

(h) Disclose any of Corporation's or Members' business practices, trade secrets, or any other confidential or proprietary information not generally known to the business community to any person not authorized to receive it.

Section 3. Loans and Guarantees. Neither participation in the activities of the Corporation nor any provision of these Bylaws or of the Certificate of Formation shall be deemed to constitute a pledge or loan of the credit of any Member for the benefit of the Corporation or a guarantee by any Member of any obligation of the Corporation.

ARTICLE XV.
BOOKS AND RECORDS; AUDIT; FISCAL YEAR

Section 1. Access to Books and Records. All Members of the Corporation will have access to the books and records of the Corporation, including financial statements and budgets; however, the Board shall establish procedures by which a Member, upon written demand stating the purpose of the demand may examine and copy the books and records of the Corporation. If necessary to protect the confidential information of the Corporation, a Member requesting examination of any of the Corporation's non-public books and records will be required to sign a confidentiality and non-disclosure agreement before viewing such information. The procedures shall include policies that provide reasonable protection against the unnecessary disclosure of information related to individual employees, including their compensation.

Section 2. Audit. At least annually, an audit of the financial statements of the Corporation shall be performed by the Auditor approved by the Board. The Auditor's opinion and the audited financial statements will be made available to all Members as described in Article XV, Section 1.

Section 3. Fiscal Year. The fiscal year of the Corporation shall be from January 1 through the following December 31, unless otherwise established by resolution of the Board.

Attachment 2:

Amended and Restated Bylaws of the
Texas Reliability Entity, Inc.
– Redline version

AMENDED AND RESTATED BYLAWS

OF

TEXAS RELIABILITY ENTITY, INC.

(A Texas Non-Profit Corporation)

Approved by Membership – November 14, 2014 ~~16, 2012~~

Approved by Federal Energy Regulatory Commission – _____ ~~June 12, 2013~~

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ARTICLE I.
DEFINITIONS

Section 1. Definitions. The capitalized terms used in these Bylaws of Texas Reliability Entity, Inc. (the "Corporation" or "Texas RE"), shall have the meanings set forth below, or if not set forth below, shall have the meanings given them in the NERC Rules of Procedure.

(a) "Affiliate" means any entity controlling, controlled by or under common control with the entity under consideration, and includes any entity (i.e., any commercial enterprise) in any of the following relationships: (i) an entity that directly or indirectly owns or holds at least five percent of the voting securities of another entity, (ii) an entity in a chain of successive ownership of at least five percent of the voting securities of another entity, (iii) an entity which shares a common parent with or is under common influence or control with another entity or (iv) an entity that actually exercises substantial influence or control over the policies and actions of another entity. Evidence of influence or control shall include the possession, directly or indirectly, of the power to direct or cause the direction of the management and/or policies and procedures of another, whether that power is established through ownership or voting of at least five percent of the voting securities or by any other direct or indirect means. In cases where the level of control or influence is disputed, the Board shall have discretion to determine whether or not the entities are Affiliates of one another. Membership in Texas RE shall not create an affiliation with Texas RE.

(b) "Board" means the Board of Directors of the Corporation.

(c) "Bulk Power System" or "BPS" means facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and facilities generating electric energy as needed to maintain transmission system reliability, but does not include facilities used in the local distribution of electricity.

(d) "Delegated Authority" means the authority delegated by NERC to the Corporation to propose and enforce NERC Reliability Standards and perform other reliability-related activities in the ERCOT Region under the Delegation Agreement executed by NERC and the Corporation and approved by the Federal Energy Regulatory Commission, pursuant to Section 215 of the Federal Power Act (16 U.S.C. §824o~~r~~).

(e) "Delegation Agreement" means the agreement between the Corporation and NERC and approved by FERC which describes the Delegated Authority and may be amended from time to time.

(f) "Electric Reliability Organization" or "ERO" means the organization that is certified by FERC pursuant to Section 39.3 of its regulations, and has received recognition by appropriate regulatory authorities in Canada and Mexico, as applicable, to establish and enforce Reliability Standards for the Bulk Power Systems of the respective countries and that has entered into a delegation agreement with the Corporation pursuant to which the Electric Reliability Organization delegates enforcement authority for Reliability Standards for the Bulk Power System in the ERCOT Region. NERC was certified as the ERO on July 20, 2006.

(g) "ERCOT Region" means the geographic area and associated transmission and distribution facilities that are not synchronously interconnected with electric utilities operating outside the jurisdiction of the Public Utility Commission of Texas.

(h) "FERC" means the Federal Energy Regulatory Commission.

(i) "Independent Director" means a person who is not (a) an officer or employee of the Corporation; (b) a NERC Registered Entity or Member or an officer, director, or employee of a Member of the Corporation; or (c) an officer, director, or employee of any company or entity that would reasonably be perceived as having a direct financial interest in the outcome of Board decisions or having a relationship that would interfere with the exercise of independent judgment in carrying out the responsibilities of a Director, as more specifically described in Article IV of these Bylaws.

~~(j) "Initial Director" means a Director named in the Certificate of Formation and seated for formation of the Corporation.~~

~~(k)~~(j) "Member" means a member of the Corporation pursuant to Article III of these Bylaws.

~~(l)~~(k) "NERC" means North American Electric Reliability Corporation, the entity certified by FERC as the ERO on July 20, 2006.

~~(m)~~(l) "NERC Rules of Procedure" means the Rules of Procedure that are adopted by NERC and approved by FERC.

~~(n)~~(m) "PUCT" means the Public Utility Commission of Texas.

(n) "OPUC" means the Texas Office of Public Utility Counsel.

(o) "Originally Elected Independent Director" means a Director approved by the membership on June 2, 2010, in the first election of Texas Reliability Entity, Inc. Independent Directors.

(p) "Regional Entity" means an entity with a Delegation Agreement with NERC, as ERO, including the following organizations, in addition to Texas Reliability Entity: Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst Corporation (RF~~C~~), Southeastern Electric Reliability Council (SERC), Southwest Power Pool (SPP), and Western Electricity Coordinating Council (WECC).

(q) "Regional Reliability Standard" means a standard for the ERCOT Region that is proposed and approved in accordance with the Texas RE Standards Development Process, as set forth in Exhibit C to the Delegation Agreement, and either, (i) sets more stringent reliability requirements than a national Reliability Standard, or (ii) covers matters not covered by a national Reliability Standard.

(r) "Registered Entity" means an entity that is registered with NERC and listed on the NERC Compliance Registry (available at www.nerc.com).

(s) "Reliability Standard" means a requirement to provide for Reliable Operation of the Bulk-Power System, which is approved by NERC and FERC, pursuant to Section 215 of the Federal Power Act an all amendments thereto. This term includes requirements for the operation of existing Bulk-Power System facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for Reliable Operation of the Bulk- Power System.

(t) "Reliable Operation" means operating the elements of the Bulk Power System within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of the Bulk Power System will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.

(u) "Sector" means a group of Members of the Corporation that are Bulk Power System owners, operators, or users, as defined in Article III, Section 4 of these Bylaws. Each Sector shall constitute a class of Members for purposes of Chapter 22 (Nonprofit Corporations) of the Texas Business Organizations Code.

ARTICLE II.
PURPOSE

Section 1. General Purpose. The purpose of the Corporation is to preserve and enhance reliability in the ERCOT Region. In furtherance of this goal, the Corporation will:

(a) Perform Reliability Standards development, compliance monitoring, compliance enforcement, and other related activities as a Regional Entity, pursuant to 16 U.S.C. §824o, in accordance with the Corporation's Delegation Agreement with NERC;

(b) Carry out other activities as set forth in the Delegation Agreement, the NERC Rules of Procedure, or as otherwise required or requested by NERC, in support of the Delegated Authority, including but not limited to organization registration and certification, reliability assessment and performance analysis, training and education, and situational awareness and infrastructure security; and

(c) Engage in any other lawful act or activity that is not in conflict with the Corporation's duties as a Regional Entity and for which non-profit corporations may be organized under the Texas Business Organizations Code.

Section 2. Non-Profit Corporation. The Corporation is a Texas non-profit corporation.

Section 3. Geographic Area. The Corporation will perform its operations primarily within the ERCOT Region. ~~The ERCOT Region includes 200,000 square miles, 85% of Texas load, and 75% of Texas land area (does not include the Panhandle, El Paso area, and 2 areas of East Texas). The ERCOT Region includes the following Texas cities and towns: Dallas, Ft. Worth, Houston, San Antonio, Austin, Paris, Tyler, Nacogdoches, Lufkin, Bryan, College Station, Corpus Christi, Harlingen, Brownsville, Laredo, Brownwood, San Angelo, Abilene, Midland, Odessa, Fort Stockton, Monahans, Snyder, Vernon, Wichita Falls, Denton, Garland, Greenville, Waco, Temple, Killeen, Weatherford, and Graham, and does not interconnect synchronously across state lines to import or export power with neighboring reliability regions.~~

ARTICLE III.
MEMBERSHIP

Section 1. Members. The Corporation is a membership corporation. Membership in the Corporation is voluntary and is open only to any entity that is a user, owner or operator of the ERCOT Region Bulk Power System, registers with the Corporation as a Member, maintains its registration in accordance with this Article III, and complies with the other conditions and obligations of membership specified in these Bylaws. All Members must qualify and be registered in one of the Sectors defined in Article III, Section 4. Membership in the Corporation is not a condition to participating in the development or consideration of proposed Regional Standards.

Section 2. Registration as a Member. Any entity that is eligible to be a Member of the Corporation in accordance with Article III, Section 1 may become a Member by completing and submitting to ~~the secretary of~~ the Corporation a membership registration on a form prescribed by the Corporation. The Member shall designate one representative and an alternative representative with authority to receive notices, cast votes, and execute waivers and consents on behalf of the Member. The Corporate ~~s~~Secretary ~~of the Corporation~~ shall maintain a current roster of the Members of the Corporation including each Member's designated representative and alternative representative. ~~From time to time, the Board shall establish a date by which Members shall submit their registration renewals.~~ All Members shall be required to renew their registrations annually. ~~and within 30 calendar days of a request by an officer of the Corporation, using a registration renewal form prescribed by the Corporation.~~ The Corporate ~~s~~Secretary ~~of the Corporation~~ shall remove any Member from the roster ~~of Members of the Corporation any Member~~ that has not submitted a registration renewal ~~within 30 days following~~ by a date established by the Corporation. ~~The secretary shall inform any Member that is removed from the roster of Members of such removal, by sending notice to such former Member's last known address on the records of the Corporation.~~

Section 3. Obligations and Conditions of Membership.

(a) Members must agree to promote, support, and comply with Reliability Standards, and assist the Corporation in its compliance with the terms and provisions of the Corporation's Delegation Agreement with NERC. Each Member shall agree, in writing, to accept the responsibility to comply with policies of NERC and the Corporation as set forth in their respective certificates of formation, bylaws, rules of procedure, and Reliability Standards, as applicable, as from time to time adopted, approved, or amended.

(b) As an additional condition of membership in the Corporation, each Member shall be required to execute an agreement with the Corporation, in a form to be specified by the Corporation, that such entity will hold all Directors, officers, employees, and agents of the Corporation, as well as volunteers participating in good faith in the activities of the Corporation, harmless for any injury or damage caused by any act or omission of any director, officer, employee, agent, or volunteer in the course of performance of his or her duties on behalf of the Corporation, other than for willful acts of misconduct.

(c) Consistent with applicable laws and regulations, Members must share nonproprietary information at the Corporation's request as necessary for the furtherance of the Corporation's activities and consistent with NERC, PUCT, or any other applicable rules relating to confidentiality.

Section 4. Membership Sectors. Each Member shall elect to be assigned to one of the following membership Sectors:

(a) **System Coordination and Planning**: An entity that is registered with NERC as a Reliability Coordinator (RC), Balancing Authority (BA), Planning Authority (PA), Resource Planner (RP), or Interchange Authority (IA).

(b) **Transmission and Distribution**: An entity that is registered with NERC as a Transmission Owner (TO), Transmission Planner (TP), Transmission Service Provider (TSP), Distribution Provider (DP), and/or Transmission Operator (TOP) and is not a Cooperative ~~–~~or Municipal Utility.

(c) **Cooperative Utility**: An entity that is (a) a corporation organized under Chapter 161 of the Texas Utilities Code or a predecessor statute to Chapter 161 and operating under that chapter; or (b) a corporation organized as an electric cooperative in a state other than Texas that has obtained a certificate of authority to conduct affairs in the State of Texas; or (c) a cooperative association organized under Tex. Rev. Civ. Stat. 1396-50.01 or a predecessor to that statute and operating under that statute and is registered with NERC for at least one reliability function.

(d) **Municipal Utility**: A municipally owned utility as defined in Public Utility Regulatory Act, Tex. Util. Code ~~PURA~~ §11.003 and is registered with NERC for at least one reliability function.

(e) **Generation**: An entity that is registered with NERC as a Generator Owner (GO) or Generator Operator (GOP).

(f) **Load-Serving and Marketing**: An entity that is registered with NERC as a Load Serving Entity (LSE), a Purchasing-Selling Entity, or any newly defined NERC reliability function for demand response.

Section 5. Participation.

(a) There is only one level of Membership, and no company or entity may simultaneously hold more than one Membership.

(b) Members must qualify in and join a Sector.

(c) A Member that is eligible for more than one Sector may join only one Sector and it must be the most appropriate Sector for its business. Any disputes regarding appropriateness of a Member's Sector will be decided by a majority vote of the Board.

(d) A company or entity that is an Affiliate of a Member may hold a separate membership in a different Sector, so long as the legal entities have different NERC Compliance Registry Numbers under which they are currently registered for the applicable NERC reliability function.

(e) A Member must continue to vote in the same Sector for a minimum of the remainder of the ~~fiscal~~ membership year in which it becomes a Member or until it is no longer eligible to remain in such Sector, and it must give notice to the Corporate S~~s~~ecretary when it elects or is required to change Sectors.

(f) The Board may review the Sector qualification of any Member and may determine that a Member does not qualify for, and require them to change Sectors.

(g) A Member which is no longer eligible or not in good standing may not vote on any matters that require membership.

Section 6. Membership Fees. Members must pay an annual Membership Fee of $250, to offset the expenses of membership qualification, coordination, and meetings, unless the Board waives the fee for any Member for good cause shown. The Board may agree to change the amount or frequency of the Membership Fee, from time to time, by majority vote.

Section 7. Term of Membership. Membership in the Corporation must be renewed on an annual basis and will only be retained as long as a Member meets its respective qualifications, obligations, and conditions of membership as set forth in these Bylaws. Membership is conditioned on the annual payment of Membership Fees, unless the Membership Fees are waived by the Board for good cause shown, as determined in the Board's sole discretion.

Section 8. Removal. No Member or Member representative may be sanctioned, expelled or suspended and no membership in the Corporation may be terminated or suspended except pursuant to a procedure that is fair and reasonable and is carried out in good faith. The Board may, by resolution, establish a procedure to terminate, expel, suspend, or sanction a Member following notice to the Member and exercise of appropriate due process procedures and a determination by the Board in its sole discretion that in its judgment the Member has violated its obligations and responsibilities to the Corporation. In the event that the Board does not adopt procedures, the following procedures shall apply:

(a) Written notice. Written notice of intent to terminate, expel, suspend or sanction a Member shall be delivered at least twenty (20) days in advance of the date when a hearing will be held to determine whether the Member shall be expelled, suspended, terminated or sanctioned. Such notice shall set forth the reasons therefore. Said notice must be given by facsimile (receipt confirmed), e-mail (receipt confirmed) or first class or certified mail sent to the last address of the Member to be expelled, suspended, terminated or sanctioned, as shown in the Corporation's records.

(b) Hearing. An opportunity shall be provided for the Member receiving such notice to be heard by the Board at the hearing, orally and in writing. The Member shall be entitled to have counsel present, and to participate in the hearing, at its own expense, and to present and cross-examine any witnesses.

(c) Liability. A Member which has been sanctioned, expelled, terminated or suspended shall remain liable to the Corporation for fees as a result of obligations incurred or commitments made prior to sanction, expulsion, termination or suspension.

(d) Challenges. Any request for a proceeding challenging an expulsion, suspension, sanction or termination, including a proceeding in which defective notice is alleged, may be submitted to the Board in writing within one year after the effective date of the expulsion, suspension, sanction or termination. If the Board determines to hear such challenge, it shall notify the Member and such proceeding will be subject to the hearing requirements described in subsection (b) above of this Section 8.

Section 9. Resignation. Any other provision of these Bylaws notwithstanding, any Member may withdraw from participation in the activities of the Corporation at any time upon

written notice to the chief executive officer or president of the Corporation, whereupon it shall cease to be a Member, and its representatives shall cease to be entitled or obligated to participate in the activities of the Board or any activities requiring membership.

Section 10. Reinstatement. A former Member may submit a written request for reinstatement of Membership. The Board will reinstate the Membership unless the entity does not meet the Membership qualifications set forth in these Bylaws.

ARTICLE IV.
BOARD OF DIRECTORS

Section 1. Board of Directors. The business and affairs of the Corporation shall be managed by the Board. The Board shall consist of (i) four (4) Independent Directors who are nominated and elected in accordance with the requirements and procedures specified in this Article IV (the "Independent Directors"); (ii) the Chairman of the PUCT or another PUCT Commissioner designated by the Chairman, as an *ex officio* non-voting member; (iii) Texas Public Counsel, from OPUC (or another employee of OPUC designated by Texas Public Counsel), as an *ex officio* non-voting member, representing the interests of residential and small commercial electricity consumers; (iv) the CEO of the Corporation as a voting member (the "Management Director"); (v) the chair of the Member Representatives Committee as a voting member; and (vi) the vice chair of the Member Representatives Committee as a voting member. The Directors who are the chair and vice chair of the Member Representatives Committee will be collectively referred to herein as "Affiliated Directors." Each Director, including the Affiliated Directors and excluding the non-voting members of the Board, shall have one (1) vote on any matter brought before the Board for a vote. All Directors are expected to serve the public interest and to represent the reliability concerns of the entire ERCOT Region Bulk Power System.

Section 2. Independent Directors. The Independent Directors shall be elected, shall have the qualifications specified, and shall serve in the manner provided in this Section.

(a) Qualifications:

(1) Experience in one or more of these fields: senior corporate leadership; professional disciplines of finance, accounting, engineering, bulk power systems, or law; regulation of utilities; and/or risk management.

(2) Independence of any NERC ~~r~~Registered ~~e~~Entity~~, including ERCOT ISO, and any ERCOT Region Market Participant~~. Requirements of independence include but are not limited to the following:

(i) Independent Directors and the spouse, mother, father, sibling, or dependent, and any spouse of mother, father, or sibling and including any step and adoptive parents, siblings or children, and household members of Independent Directors and their spouses shall not have current or recent status (within the last two years) as a director, officer, or employee of an ERCOT Region NERC Registered Entity~~ or ERCOT Region Market Participant~~.

(ii) Independent Directors and immediate family (any spouse or dependent) and household members of Independent Directors shall not have current status as a director, officer, or employee of a non-ERCOT Region NERC Registered Entity.

(iii) Independent Directors and immediate family and household members of Independent Directors shall not have direct business relationships, other than retail customer relationships, with any NERC Registered Entity ~~or Market Participant~~.

(iv) Independent Directors and immediate family and household members of Independent Directors shall not own stocks or bonds of NERC Registered Entities or their affiliates. To the extent that an Independent Director or his or her spouse, dependent child, or any other household member owns stocks or bonds of NERC Registered Entities ~~or Market Participants~~, these must be divested or placed in a blind trust prior to being seated on the Board. Ownership in broadly diversified mutual funds or similar funds, which may include stocks or bonds of NERC Registered Entities or their affiliates, is not prohibited.

(v) Independent Directors shall not have any relationship that would interfere with the exercise of independent judgment in carrying out the responsibilities of a Board member, including the Delegated Authority.

(vi) Other criteria as approved by the Board.

(b) Term. ~~Except for the Initial and originally elected Directors, t~~The term for Independent Directors shall be staggered three year terms. An Independent Director may be elected for up to three consecutive terms. ~~Notwithstanding the foregoing, the Directors named as Initial Directors will serve only until the first membership meeting of the Corporation at which Independent Directors are elected. If an Initial Director is qualified to be an Independent Director and elected by the membership, such Director's term as an Initial Director shall not be counted for purposes of term limits.~~ For the ~~o~~Originally Eelected Independent Directors, two positions will have three~~-~~year terms, one position will have a two~~-~~year term, and one position will have a one~~-~~year term, and these terms shall not be counted for purposes of term limits. The term for the Affiliated Directors who are chair and vice chair of the Member Representatives Committee shall be ~~one~~ two years, and the terms of the *ex officio* Directors will not expire. If an Independent Director is elected to fill an unexpired term in the event of a vacancy, that term shall not be counted for purposes of term limits.

(c) Selection.

(1) ~~Except for the selection of the Initial Directors, t~~The Board shall appoint, on an annual basis, or more frequently if needed in the event of a special election pursuant to this subsection, a nominating committee (the "Nominating Committee") to recommend candidates (i) to succeed the Independent Directors whose terms expire during the current year and (ii) to serve the remainder of the term of any Independent Director who ceased to serve as a Director subsequent to the last annual election of Directors. ~~Except for the original Nominating Committee appointed by the Initial Directors ("Initial Nominating Committee"), t~~The Nominating Committee shall consist of ~~all~~ two (2) Independent Directors ~~except those~~ whose terms do not expire during the current year and are not seeking re-election and one (1) Affiliated Director~~.s and such other persons with such qualifications as the Board shall specify (provided that such other persons may not vote), provided that the Independent Directors shall constitute a majority of the voting members of the Nominating Committee. The Initial Nominating Committee will consist of the Initial Directors except the Management Director (as defined in Article IV, Section 3), and at least two other persons selected by these Initial Directors to represent the interests of the~~

~~Membership.~~ The PUCT Chairman (or the PUCT Commissioner designated by the Chairman) may choose to participate on the Nominating Committee. ~~If any Nominating Committee should have only two eligible Independent Directors for any reason, the requirement that Independent Directors must constitute a majority of the voting members will be removed to allow both Affiliated Directors to participate on the Nominating Committee.~~ The Board Chair shall appoint the Chair of the Nominating Committee. The Nominating Committee may retain an executive search firm to locate and present candidates with the required qualifications, as set forth in Article IV, Section 2(a). Meetings of the Nominating Committee are not required to be publicly posted.

(2) The Nominating Committee shall ~~interview the qualified candidates and~~ select and nominate, by at least a two-thirds majority, qualified candidate(s) to present to the Membership for its approval. ~~., consistent with the~~The Nominating Committee shall strive to ensure that ~~objectives that~~ the Board as ~~an entirety shall~~a whole reflects expertise in the areas of technical electric operations and reliability, legal, senior corporate leadership, financial, risk management, and regulatory matters, and familiarity with regional system operation issues in the ERCOT Region~~, to present to the Membership for its approval~~.

(3) The Membership shall vote by Sector as described in Article V in favor or against the proposed Independent Director(s). A proposed Independent Director who is approved by a majority of the Sectors shall become an Independent Director.

(d) Director Voting Weights. All voting Directors shall have a single vote each.

(e) Alternates and Proxies. Independent Directors may designate another Independent Director as a proxy if unable to attend a Board meeting. Ex officio Directors may designate a selected proxy or an alternate representative who may attend meetings in the absence of such Director. The chair and vice chair of the Member Representatives Committee may designate each other or may designate an Independent Director as their proxy if unable to attend a Board meeting.

Section 3. Appointment of Management Director. The president and chief executive officer (CEO) of the Corporation shall serve as the Management Director of the Corporation, effective as of the date of his or her appointment by the Board as CEO of the Corporation in accordance with these Bylaws, to serve until such time that he or she ceases to hold the position of CEO. No action of the Members of the Corporation shall be required in connection with the appointment of the CEO as the Management Director of the Corporation.

Section 4. Chair and Vice Chair. Annually, the Board shall elect from the Board's membership, by resolution of the Board, a Chair and a Vice Chair. The Chair and Vice Chair shall each be one of the Independent Directors.

Section 5. Vacancies and Removal.

(a) Should any vacancy on the Board arise from the death, resignation, retirement, disqualification, or removal from office of any Director, or from any other cause, such vacancy shall be filled as follows:

(1) For an Independent Director, by the election of a new Independent Director at the next annual election of Directors to fill the remainder, if any, of the term of the departed Independent Director; provided, that the Board by resolution may in its discretion call a special election to fill any such vacancy for the remainder, if any, of the term of the departed Independent Director.

(2) For the Management Director, by the appointment of a new CEO or interim CEO to fill the vacancy.

(3) For an ex officio Director, by the appointment of a new PUCT Chair or Texas Public Counsel by whomever had the right to appoint such Director.

(4) For an Affiliated Director, by the election of a new chair or vice chair, as applicable, by the Member Representative Committee.

(b) A Director may be removed with or without cause at any time by whomever had the right to appoint such Director (for ex officio Directors), or for the elected Independent Directors, by an affirmative vote of sixty percent (60%) of the Members. In addition, the Board may remove any voting Director for cause, upon at least seventy-five percent (75%) affirmative votes of the eligible, remaining voting Directors. The right to elect Directors may not be assigned, sold, pledged or transferred in any manner.

Section 6. Committees of the Board. The Board shall by resolution create and appoint all committees of the Board as the Board deems necessary to perform its responsibilities. All committees of the Board shall have such duties as are prescribed and delegated by the Board. Committees to which any of the authority of the Board to manage the Corporation is delegated must have at least two Directors, and a majority of the members of the committee must be Directors.

ARTICLE V.
MEETINGS OF MEMBERS OF THE CORPORATION

Section 1. Annual and Other Meetings of Members.

(a) An annual meeting of the Members to elect Directors, announce election results from electronic elections, and conduct such other business as may come before the meeting, shall be held ~~on or about~~in December ~~1 of~~ each year ~~or as soon thereafter as is reasonably practicable~~. The failure to hold an annual meeting in accordance with these bylaws shall not affect the validity of a corporate action.

(b) Meetings of Members of the Corporation may be called for any purpose or purposes by resolution of the Board, by the chair of the Board, the CEO or the Corporate ~~s~~Secretary ~~of the Corporation~~, or by a number of Members constituting at least ten (10) percent of all Members on the roster of Members maintained by the Corporate ~~s~~Secretary ~~of the Corporation~~, which number shall include Members in at least three (3) of the Sectors. Meetings of Members shall be held at the principal office of the Corporation or at such other place fixed by the Board as shall be specified in the notice of meeting. Meetings shall be called upon written notice of the time, date, place, and purposes of the meeting given to all Members on the roster of Members maintained by the Corporate ~~s~~Secretary ~~of the Corporation~~ not less than ten (10) nor more than sixty (60) days prior to the date of the meeting. Only Members in good standing with the Corporation, as determined by the Board, have the right to vote at any meeting of the Members. Further, if at any point a Member no longer meets the qualifications for the Sector of

which it is a member, the Entity may immediately elect to become a member in any Sector for which it does qualify.

Section 2. Quorum and Voting Requirements for Meetings of Members.

(a) At any meeting of the Members of the Corporation, attendance in person or by proxy by a majority of the Members in each of at least two-thirds of the Sectors on the roster of Members maintained by the Corporate ~~s~~Secretary ~~of the Corporation~~ shall constitute a quorum.

(b) Except as otherwise expressly provided in the Corporation's Certificate of Formation, these Bylaws, or applicable law, Members shall vote by Sector and each Sector shall have one vote.

(c) To the extent practicable, membership votes will be conducted electronically and prior to annual membership meetings.

(d) Except as otherwise expressly provided in the Corporation's Certificate of Formation, these Bylaws or applicable law, actions by the Members of the Corporation shall be approved upon receipt of the affirmative vote of a majority of the Sectors of the Corporation at (1) a meeting at which a quorum is present, in person or by proxy, or (2) an electronic vote which has participation by a quorum. Each Sector's vote shall be determined by the affirmative vote of a majority of the members of the Sector voting at the meeting or in the electronic election.

Section 3. Waivers of Notice of Meetings of Members and Member Meeting Adjournments. Notice of a meeting of Members need not be given to any Member who waives notice, either electronically or in writing, in person or by proxy, whether before, during, or after the meeting. The attendance of any Member at a meeting, in person or by proxy, without protesting prior to the conclusion of the meeting the lack of proper notice of such meeting, shall constitute a waiver of notice of the meeting by such Member. When any meeting of Members is adjourned to another time or place, it shall not be necessary to give notice of the adjourned meeting if the time and place to which the meeting is adjourned are announced at the meeting at which the adjournment is taken, and if at the adjourned meeting only such business is transacted as might have been transacted at the original meeting.

Section 4. Action Without a Meeting of Members. Any action, required or permitted to be taken at a meeting of Members, may be taken without a meeting if the proposed action is posted to all Members (via direct email or email to an email distribution list to which Members may subscribe and by posting on the Corporation website) and consented to in writing by the minimum number of Members that would be required to approve the action at a meeting of the Members at which all Members were present. The voting in such a circumstance shall be performed in writing, including via email or other electronic means. The Members shall receive written notice of the results within ten (10) days of the action vote, and all written responses of the Members shall be filed with the Corporate records. The results of such voting will be posted on the Corporation's website.

Section 5. Meetings of the Members to be Open. Notice to the public of the dates, places, and times of meetings of the Members, and all non-confidential material provided to the Members, shall be posted on the Corporation's website at approximately the same time that notice is given to the Members. Meetings of the Members shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided, that the meeting may be held in or adjourned to closed session to discuss matters of a confidential nature, including but not limited to compliance and enforcement matters, personnel matters, litigation, or

commercially sensitive or critical infrastructure information of the Corporation or any other entity. The results of any action taken without a meeting, as described above, will be posted on the Corporation's website.

ARTICLE VI.
MEETINGS OF THE BOARD OF DIRECTORS

Section 1. Regular Meetings of the Board. Regular meetings of the Board shall be held at least quarterly. By resolution adopted at any meeting of the Board, the Board may provide for additional regular meetings that may be held as needed.

Section 2. Special Meetings of the Board. Special meetings of the Board for any purpose or purposes may be called at any time by the chair or by any two Directors. Such meetings may be held upon notice given to all Directors not less than three (3) days prior to the date of the meeting. Such notice shall specify the time, date, place, and purpose or purposes of the meeting and may be given by telephone, email or other electronic media, or by express delivery.

Section 3. Quorum and Voting Requirements for Meetings of the Board. ~~The Board consisting of the Initial Directors ("Initial Board") may conduct only organizational business of the corporation, including but not limited to approving these Bylaws, authorizing the opening of a bank account, appointing officers, approving the Delegation Agreement and reviewing and approving the Corporation's business plan and budget. The quorum necessary for transaction of business by the Initial Board shall be a majority of the Initial Directors, either in person or by proxy, at meetings at which a quorum is present. Thereafter, u~~ Unless otherwise expressly provided in the Corporation's Certificate of Formation, these Bylaws or applicable law, (i) the quorum necessary for the transaction of business at meetings of the Board shall be a majority of the voting Directors in person or by proxy and at least three Independent Directors, and (ii) actions by the Board shall be deemed approved upon receipt of the affirmative vote of a majority of the Directors present and voting in person (by means of any communications system by which all persons participating in the meeting are able to hear each other) or by proxy at a meeting at which a quorum is present but in no case less than four votes.

Section 4. Meetings of the Board to be Open. Notice to the public of the dates, places, and times of meetings of the Board, and all non-confidential material provided to the Board, shall be posted on the Corporation's website at approximately the same time that notice or such material is given to the Directors and at least five (5) business days prior to the scheduled meeting~~; provided however that the Board may meet on urgent matters on such shorter notice, not less than two (2) hours, as the person(s) calling such meeting may deem necessary or appropriate for urgent matters (emergency conditions threatening health or safety or a reasonably unforeseen situation)~~. Meetings of the Board shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided, that the Board may meet in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to compliance and enforcement matters, personnel matters, litigation, or commercially sensitive or critical infrastructure information of the Corporation or any other entity. Any or all of the Directors or members of a Board committee, may participate in a meeting of the Board, or a meeting of a committee, in person or by proxy, by means of any communications system by which all persons participating in the meeting are able to hear each other.

Section 5. Waivers of Notice of Board Meetings and Board Meeting Adjournments. Notice of a board meeting need not be given to any Director who signs, or sends an email confirming a waiver of notice, in person or by proxy, whether before, during, or after the

meeting, or who attends the meeting without protesting the lack of notice of such meeting, prior to the conclusion of the meeting, the lack of notice of such meeting. Notice of an adjourned board meeting need not be given if the time and place to which the meeting is adjourned are announced at the meeting at which the adjournment is taken and if the period of adjournment does not exceed ten (10) days.

Section 6. Action Without a Meeting. Any action required or permitted to be taken at a meeting of the Board, or of any committee thereof, may be taken by the Board or by the committee without a meeting if the action is consented to in writing by the number of Directors or members of the committee, as the case may be, entitled to vote on the action that would be required to approve the action at a meeting of the Board or committee with all members of the Board or committee present. The call for action without a meeting of the Board may be initiated by the chair or by any two voting Directors. Notice of the proposed call for action without a meeting, and all non-confidential material provided to the Board in connection with the call for action without a meeting, shall be posted on the Corporation's website and shall be sent via email to an email distribution list to which Members and the public may subscribe at approximately the same time notice of the call for action without a meeting or such material is provided to the Board. The call for action without a meeting of a committee of the Board may be initiated by the chair of the committee or by any two members of the committee. The Directors or members of the committee shall receive written notice of the results of such action within seven (7) days of the action vote. All written responses of the Directors shall be filed with the minutes of the Corporation, and all written responses of members of a committee shall be filed with the minutes of such committee.

Section 7. Emergency Meetings. The Board may meet on urgent matters with not less than two (2) hours' public notice, as necessary or appropriate for emergency conditions threatening health or safety or a reasonably unforeseen situation.

ARTICLE VII.
OFFICERS

Section 1. Selection of Officers. At a meeting held in accordance with Article VI of these Bylaws, tThe Board shall elect a CEO and shall approve ratify the selection of a corporate secretary and such otherthe officers of the Corporation (collectively, the "Officers"). as it shall deems necessary. The CEO shall be nominated and elected by the Board. All of the other Officers shall be selected by the CEO and approved by the Board, and the removal of all Officers shall be confirmed by the Board. The Management Director shall not participate in votes electing or ratifying, approving, or removing Officers. The Corporation shall maintain a list of current Officers ratified by the Board. The duties and authority of the Officers shall be determined from time to time by the Board. Subject to any such determination, the Officers shall have the following duties and authority:

Section 2. Chief Executive Officer ("CEO"). The CEO shall be the chief executive officer of the Corporation. He or she shall be responsible for the day-to-day ongoing activities of the Corporation and shall have such other duties as may be delegated or assigned to him or her by the chair. The CEO may enter into and execute in the name of the Corporation contracts or other instruments not in the regular course of business that are authorized, either generally or specifically, by the Board.

Section 3. Corporate Secretary. The secretary shall maintain the roster of Members of the Corporation, shall cause notices of all meetings to be served as prescribed in

these Bylaws, shall keep or cause to be kept the minutes of all meetings of the Members and the Board, and shall have charge of the seal of the Corporation. The secretary shall perform such other duties and possess such other powers as are incident to his or her office or as shall be assigned to him or her by the CEO. The CEO may select an Assistant Corporate Secretary at his or her discretion. The Assistant Corporate Secretary is not an Officer of the Corporation.

Section 4. Chief Financial Officer. ~~If hired and approved, a~~A ~~c~~Chief ~~f~~Financial ~~o~~Officer shall have custody of the funds and securities of the Corporation, shall keep or cause to be kept regular books of account for the Corporation and shall have the duties normally assigned to a treasurer of a corporation. The ~~c~~Chief ~~f~~Financial officer shall perform such other duties and possess such other powers as are incident to his or her office or as shall be assigned to him or her by the CEO.

Section 5. ~~Vice Presidents~~Other Officers. The CEO may select such other ~~Corporate o~~Officers as he or she deems appropriate, subject to ratification by the Board ~~approval~~. Any such ~~o~~Officer shall perform such other duties and possess such powers as are incident to his or her office or as shall be assigned to him or her by the CEO.

ARTICLE VIII.
RELIABILITY STANDARDS COMMITTEE

Section 1. Requirement. The Corporation shall have a Reliability Standards Committee, which shall operate in accordance with the Standards Development Process as set forth in Exhibit C to the Delegation Agreement with NERC and approved by FERC. The chair and vice chair of the Standards Committee must be accepted or approved by the Board, in accordance with said Exhibit C.

ARTICLE IX.
MEMBER REPRESENTATIVES COMMITTEE

Section 1. Purpose of Member Representatives Committee. The Corporation shall have a "Member Representatives Committee" that shall provide advice and recommendations to the Board with respect to: annual budgets, business plans and funding mechanisms of the Corporation; other matters relevant to reliability of the ERCOT Bulk Power System; and other matters pertinent to the purpose and operations of the Corporation. The Member Representatives Committee shall provide its advice and recommendation to the Board through its chair and the vice chair, who also serve as the Affiliated Directors on the Board. The Member Representatives Committee may create subcommittees, task forces, or working groups ("subcommittees") as it deems appropriate to study or discuss selected technical or compliance matters and to make recommendations to the Board as requested or required by the Board or as deemed appropriate to its purpose by the Member Representatives Committee. Because it is elected by the Members of the Corporation and not appointed by the Board, the Member Representatives Committee shall not be a standing committee of the Board of Directors of the Corporation, but is authorized to provide advice and recommendations directly to the Board, through its elected chair and vice chair.

Section 2. Composition of the Member Representatives Committee. The Member Representatives Committee shall consist of two representatives from each Sector to serve ~~annually~~ two-year terms and will ~~annually~~ select a chair and vice chair for the Member Representatives Committee to serve two-year terms. The representatives of each Sector shall be officers, employees, or directors of Members in that Sector ~~-~~(or the Member's parent, subsidiary, or other Affiliate); provided however, except for a Sector that has only one Member, only one

officer, employee, or director of a Member in a Sector (or the Member's parent, subsidiary, or other Affiliate) may be a representative from that Sector. The Board may by resolution create additional non-voting positions on the Member Representatives Committee on its own initiative or at the written request of any group of Members of the Corporation that believes its interests are not adequately represented on the Member Representatives Committee. There shall be no limit on the number of terms that an officer, employee, or director of a Member (or the Member's parent, subsidiary, or other Affiliate), may serve on the Member Representatives Committee.

Section 3. Election of Representatives of the Member Representatives Committee. Unless a Sector adopts an alternative election procedure, the annual election of representatives from each Sector to the Member Representatives Committee, and any election to fill a vacancy, shall be conducted in accordance with the following process, which shall be administered by the officers of the Corporation.

(a) During the period beginning no more than ninety (90) days and ending no less than fifteen (15) days prior to an annual meeting, or beginning no more than forty-five (45) days and ending no less than fifteen (15) days prior to a special election- to fill a vacancy on the Member Representatives Committeemeeting called in whole or in part to hold an election to fill a vacancy, nominations may be submitted for candidates for election to the Member Representatives Committee. A nominee for election as a Sector representative must be an officer, employee, or director of a Member in that Sector (or the Member's parent, subsidiary, or other Affiliate). No more than one nominee who is an officer, employee, or director of a Member (or the Member's parent, subsidiary, or other Affiliate) may stand for election in any single Sector; if more than one officer, employee, or director of a Member (or the Member's parent, subsidiary, or other Affiliate) is nominated for election from a Sector, the Member shall designate which such nominee shall stand for election. The election of representatives shall be conducted over a period of ten (10) days using an electronic process approved by the Corporate sSecretary of the Corporation.

(b) Each Member in a Sector shall have one vote for each Representative to be elected from the Sector in that election and may cast no more than one vote for any nominee. The nominee receiving the highest number of votes in each Sector shall be elected to one Representative position to be filled from that Sector and the nominee receiving the second highest number of votes shall be elected as the second Representative position for that Sector. To be elected on the first ballot, a nominee must receive a number of votes equal to a simple majority of the Members in the Sector casting votes in the election. If no nominee in a Sector receives a simple majority of votes cast in the first ballot, a second ballot shall be conducted which shall be limited to the number of candidates receiving the three (3) highest vote totals on the first ballot. The nominees receiving the two highest totals of votes on the second ballot shall be elected to the Representative positions for the Sector.

(c) A Sector may adopt an alternative procedure to the foregoing to nominate and elect its Representatives to the Member Representatives Committee if –the alternative procedure is approved by vote of at least two-thirds of the Members in the Sector, provided, however that any alternative procedure may be reviewed and disapproved by the Board.

(d) A Sector may elect an Alternate to serve in place and at the convenience of the Sector's Member Representatives Committee Representative(s) in the event a Member Representatives Committee Representative cannot attend a Member Representatives Committee meeting.

Section 4. Chair and Vice Chair of the Member Representatives Committee. After the annual selection of its Representatives, the Member Representatives Committee shall

select a chair and vice chair from among its voting Representatives by majority vote to serve during the upcoming two-year term and be the Affiliated Directors on the Board. The selected chair and vice chair may not be representatives of the same Sector and may not concurrently serve on the Board of ERCOT ISO. The Board shall be notified of the selection of the chair and vice chair, but the selection will not be subject to approval of the Board. The chair is responsible for ensuring that minutes of the meetings are properly maintained and made available to the public, but the chair may delegate this responsibility to the vice chair or to another Representative of the Member Representatives Committee who may be designated as secretary of the Member Representatives Committee.

Section 5. Vacancies on the Member Representatives Committee. In the event that any Representative of the Member Representatives Committee ceases to serve as a Representative of the Member Representatives Committee as a result of his or her death, resignation, retirement, disqualification, removal, or other cause, the Members in the Sector of which such Representative was a representative shall elect, as soon thereafter as reasonably practicable, and in accordance with the procedures in this Article IX, a new Representative to replace the Representative of the Member Representatives Committee who ceased to serve. For those Sectors that have elected an Alternate, the Alternate will fill a vacancy left by the Sector's Member Representative and a new Alternate will be elected by the Sector.

Section 6. Meetings of the Member Representatives Committee. The Member Representatives Committee will plan and hold quarterly meetings, at a time and place determined by the Member Representatives Committee, normally shortly before the regular meetings of the Board, and posted on the Corporation's website. Except for closed session meetings specifically allowed by this Section, all meetings shall be open to the public. The Member Representatives Committee shall adopt such procedural rules as are needed to operate in accordance with its purpose and will include procedures for coordinating with employees of the Corporation who provide administrative support, as set forth in subsection 6(c), below.

(a) Notice to the public of the dates, places, and times of meetings of the Member Representatives Committee and any subcommittees thereof, and all non-confidential material provided to the Representatives on the Member Representatives Committee or any subcommittees thereof, shall be posted on the Corporation's website at approximately the same time that notice or such material is given to the Member Representatives Committee, which will normally be at least five (5) business days ~~one week~~ prior to ~~any~~ the scheduled meeting. Meetings of the Member Representatives Committee shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided, that the Member Representatives Committee may meet in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to confidential planning information, critical infrastructure information, or commercially sensitive information of the Corporation or any other entity. Any or all Representatives of, and any other participants in, the Member Representatives Committee may participate in a meeting of the Member Representatives Committee by means of a communications system by which all persons participating in the meeting are able to hear each other.

(b) Special meetings may be called for any purpose or purposes by the chair of the Member Representatives Committee or by any three (3) Representatives of the Member Representatives Committee, which number shall include representatives from at least three Sectors, and require notice given to all Representatives of the Member Representatives Committee not less than seven (7) days prior to the date of the meeting. Such notice shall specify the time, date, place, and purpose or purposes of the meeting and may be given by telephone, facsimile, or other electronic media, or by express delivery.

(c) The Member Representatives Committee shall effectively coordinate with the employees of the Corporation and adopt procedural rules for the voting for Representatives, scheduling of meetings, and public posting of required meeting information and minutes. The chair or vice chair of the Member Representatives Committee shall provide all meeting agendas, material, minutes and other information required or desired to be posted on the Corporation's website to appropriate Corporation employees at least one business day prior to the time such information should be posted.

Section 7. Waivers of Notice of Meetings of the Member Representative Committee and Meeting Adjournments. Notice of a meeting of the Member Representatives Committee need not be given to any member of the Member Representatives Committee who waives notice electronically or otherwise in writing, in person or by proxy, whether before or after the meeting, or who attends the meeting without protesting, prior to the conclusion of the meeting, the lack of notice of such meeting. Notice of an adjourned meeting of the Member Representatives Committee need not be given if the time and place to which the meeting is adjourned are announced at the meeting at which the adjournment is taken and if the period of adjournment does not exceed ten (10) days.

Section 8. Quorums and Voting for Meetings of the Member Representatives Committee. The quorum necessary for the transaction of business at meetings of the Member Representatives Committee shall be the presence, in person or by proxy, of two-thirds of the voting Representatives on the Member Representatives Committee entitled to attend. Each voting member of the Member Representatives Committee shall have one (1) vote on any matter coming before the Member Representatives Committee that requires a vote. Except as otherwise expressly provided in the Corporation's Certificate of Formation, these Bylaws or applicable law, actions by members of the Member Representatives Committee shall be approved upon receipt of the affirmative vote of a majority of the voting members of the Member Representatives Committee present (by means of any communications system by which all persons participating in the meeting are able to hear each other) and voting at any meeting at which a quorum is present.

Section 9. Alternates and Proxies. Member Representatives may designate another Member Representative or an employee of the Member Representative's organization (or the Member's parent, subsidiary, or other Affiliate) as a proxy if both the Member Representative and the Sector Alternate are unable to attend a Member Representatives Committee meeting. A member of the Member Representatives Committee may give a proxy only to a person who is an officer, employee, or director of a Member, registered in the same Sector (or the Member's parent, subsidiary, or other Affiliate).

Section 10. Other Procedures of the Member Representatives Committee. ~~The chair of the Board shall preside at the initial meeting of the Member Representatives Committee, until a chair is selected in accordance with Article IX, Section 4.~~ Except as to any matter as to which the procedure to be followed by the Member Representatives Committee is expressly set forth in these Bylaws, the Member Representatives Committee may adopt such additional procedures, not inconsistent with these Bylaws, as it deems appropriate, subject to review and disapproval by the Board.

ARTICLE X.
OTHER COMMITTEES AND SUBCOMMITTEES

Section 1. Committees of the Corporation. In addition to those committees specified by these Bylaws, to which the Board shall appoint members in accordance with the

requirements of these Bylaws, the Board may by resolution create standing committees of the Corporation; and may in addition by resolution appoint the members of such committees, subcommittees, task forces and Sector-specific forums as the Board deems necessary or desirable to carry out the purposes of the Corporation. The Board shall appoint members to such standing committees and other committees of the Corporation that are representative of Members, other interested parties, and the public, that provide for balanced decision-making and that include persons with sufficient technical knowledge and experience. All committees, subcommittees, task forces and Sector-specific forums shall have such scope and duties, not inconsistent with law, as are specified in these Bylaws and the Rules of Procedure of the Corporation or otherwise determined by the Board.

ARTICLE XI.
BUDGETS AND FUNDING

Section 1. Compensation of the Board and Member Representatives Committee. The Board shall have the right to fix from time to time, by resolution adopted by a majority of the Directors including a majority of the Independent Directors then serving as Directors, the amount of the annual retainer fee or other compensation to be paid to the Independent Directors for their services to the Corporation, including any fees to be paid for each meeting of the Board or any Board committee attended by an Independent Director. The Board will evaluate the fee or other compensation at least every three years, to ensure that Director compensation is appropriate. No compensation shall be paid to any Management Director, Affiliated Director, or *ex officio* Director for his or her services on the Board, other than the compensation paid to the Management Director for services as CEO of the Corporation. No compensation shall be paid by the Corporation to any member of the Member Representatives Committee for his or her services on the Member Representatives Committee. Independent Directors shall be entitled to be reimbursed their reasonable out-of-pocket expenditures for attending meetings and conducting the business of the Corporation.

Section 2. Preparation and Adoption of Annual Budget, Business Plan, and Funding Mechanism. The Board shall require the CEO to prepare for Board approval an annual business plan and budget for the administrative and other expenses of the Corporation, including the expenditures for the fiscal year for any material special projects undertaken by the Corporation and reasonable and proper reserves and provisions for contingencies, in accordance with all NERC and FERC requirements. The annual business plan, budget and funding mechanism of the Corporation shall be for a fiscal year commencing on January 1 and ending on December 31. Each annual business plan, budget, and funding mechanism shall be approved by the Board at a regular meeting or a special meeting of the Board duly called for that purpose. The Board shall approve each annual business plan, budget, and funding mechanism at a time that allows for timely submittal of the approved annual business plan, budget, and funding mechanism to the applicable regulatory authorities.

Section 3. Comments During Preparation of Annual Business Plan and Budget. In preparing the annual business plan and budget, the Board shall require that the CEO post a draft business plan and budget for review and comment by the Members of the Corporation, the Member Representatives Committee, and the standing committees of the Corporation for at least five (5) business days prior to the date of the meeting of the Board at which the annual business plan and budget is to be adopted.

Section 4. Modified or Supplemental Budgets. During the course of a fiscal year, the Board may modify any approved budget or develop and approve a supplemental budget if determined by the Board to be necessary due to such factors as a shortfall in revenues of the

Corporation from projected levels, incurred or anticipated expenditures, duties, or new projects not provided for in the annual budget, or such other factors as in the judgment of the Board warrant modification of the budget for the fiscal year or development of a supplemental budget. In preparing a modified or supplemental budget, the Board shall follow the provisions of this Article XI, Section 4 to the extent practicable in the judgment of the Board in light of the urgency of the circumstances necessitating preparation and approval of the modified or supplemental budget. Each modified or supplemental budget shall be approved by the Board at a regular meeting or a special meeting of the Board duly called for that purpose.

Section 5. Submission of Annual Business Plans and Budgets to the Regulatory Authorities. Each annual budget, annual business plan, and annual, modified, or supplemental budget approved by the Board shall be submitted by the Corporation to the ERO and any applicable regulatory authorities for approval in accordance with its regulations, and shall not be effective until approved by the applicable regulatory authorities. If ordered to modify or remand an annual budget, business plan, or annual, modified, or supplemental funding mechanism, the Board shall promptly following such order adopt such modifications to the business plan, budget , or funding mechanism as are required or directed by the order of the ERO and any applicable regulatory authority.

ARTICLE XII.
AMENDMENTS TO THE BYLAWS

Section 1. Amendments to the Bylaws. These Bylaws may be altered, amended, or repealed by action of the Membership, as set forth below. Any alteration, amendment, repeal or adoption of Bylaws shall be subject to any applicable requirements for filing with or approval by the ERO or any other applicable regulatory authority. These Bylaws may be altered, amended, or repealed as follows:

(a) Any Director or Member suggesting amendments to these Bylaws must submit a proposal of the amendment, including any necessary supporting documents, to the CEO.

(b) The CEO shall place the proposal on the agenda for a Board meeting in the time and manner prescribed by the Board and within ninety-five (95) days of the request.

(c) If the proposal is approved by an act of the Board as set forth in Article VI, Section 3, the Board shall place the proposal on the agenda of the next Annual Meeting of the Corporate Members unless the Board in its discretion calls a Special Meeting of the Corporate Members to vote on the proposal or determines to seek Membership approval without a meeting as provided in Article V, Section 4.

(d) If the proposal is not approved by the Board, the Members of the Corporation may call a meeting, pursuant to Article V, Section 1(b), for the purpose of voting on a proposal not approved by the Board. Any such proposal must be approved by a vote of five of the six Sectors at a meeting of Members called for that purpose or by written consent of five of the Sectors, where the number of votes for and against the proposed alteration, amendment, repeal or adoption of Bylaws shall be determined in accordance with Article V, Section 2.

ARTICLE XIII.
INDEMNIFICATION; PROCEDURE; DISSOLUTION

Section 1. Indemnification. The Corporation shall indemnify each person who at any time shall serve, or shall have served, as an officer, Director, employee, or other corporate agent of the Corporation, is or was serving at its request as a director, officer, partner, venturer, proprietor, employee, agent or similar functionary of another foreign or domestic corporation, partnership, joint venture, sole proprietorship, trust, employee benefit plan or other enterprise ("Indemnified Parties"), to the full extent from time to time permitted by the Texas Business Organizations Code and other applicable law. Such right of indemnification shall inure to the benefit of the legal representative of any such Indemnified Party. The foregoing indemnification shall be in addition to, and not in restriction or limitation of, any privilege or power that the Corporation may have with respect to the indemnification or reimbursement of its Indemnified Parties. The Corporation shall also pay or advance reasonable expenses incurred by an Indemnified Party in connection with a proceeding in advance of the final disposition of the proceeding upon receipt of a written affirmation by the Indemnified Party of a good faith belief that the standard of conduct necessary for indemnification under this Article XIII and the Texas Business Organizations Code has been met and a written undertaking by or on behalf of the officer, Director, or other corporate agent to repay the amount if it shall be ultimately determined that the Indemnified Party was not entitled to be indemnified by the Corporation.

Section 2. Parliamentary Rules. In the absence of and to the extent not inconsistent with specific provisions in these Bylaws, meetings or other actions pursuant to these Bylaws shall be governed by procedures that the Board may, from time to time, establish by resolution.

Section 3. Dissolution. Upon dissolution of the Corporation, in accordance with the Certificate of Formation, the remaining assets of the Corporation after payment of debts shall be distributed in the manner determined by the Board, provided that, (i) no part of the assets shall be distributed to any Director of the Corporation, and (ii) the distribution of assets shall be consistent with the requirements of Section 501(c)(3) of the United States Internal Revenue Code of 1954.

ARTICLE XIV.
CONFLICTS OF INTEREST

Section 1. Conflicts of Interest.

(a) Each Director shall have an affirmative duty to disclose to the Board or committee (as the case may be) any actual or potential conflicts of interest of the Director that arise during his or her tenure as a Director where, and to the extent that, such conflicts or potential conflicts directly or indirectly affect any matter that comes before the Board. A Director with a direct or potentially conflicting interest in a matter shall recuse himself from deliberations and actions on the matter in which the conflict arises and shall abstain on any vote on the matter and not otherwise participate in a decision on the matter. ~~—~~Any disclosure of a potential conflict of interest by a Director shall be noted in the minutes of the Board meeting at which the direct interest is disclosed. Mere attendance at the meeting, without participating in discussion of the issue raising the potential conflict, shall not constitute participation.

(b) The Corporation may not make any loan to a Director, committee member or officer of the Corporation. A Member, Director, officer, or committee member of the Corporation may not lend money to, or otherwise transact business with, the Corporation except as otherwise provided by these Bylaws, the Certificate of Formation, and applicable law. A related party transacting business with the Corporation has the same rights and obligations relating to those matters as other persons transacting business with the Corporation, provided the related party

nature of the transaction is known to the Board. The Corporation may not borrow money from, or otherwise transact business with, a Member, Director, officer, or committee member of the Corporation unless the transaction is described fully in a legally binding instrument, is in the Corporation's best interests, and is on terms no less favorable to the Corporation than could be obtained in an arms-length transaction. The Corporation may not borrow money from, or otherwise transact business with, a Member, Director, officer, or committee member of the Corporation without full disclosure of all relevant facts and without the Board's approval, not including the vote of any person having a personal interest in the transaction.

Section 2. Prohibited Acts. No Member, Director, officer, or committee member of the Corporation may do any of the below-listed prohibited acts. Engaging in these prohibited acts may lead to sanction, suspension, expulsion or termination after a hearing as described in these Bylaws. The prohibited acts include the following:

(a) Do any act in violation of these Bylaws.

(b) Do any act in violation of a binding obligation of the Corporation except with the Board's prior approval.

(c) Do any act with the intention of harming the Corporation or any of its operations.

(d) Receive an improper personal benefit from the operation of the Corporation.

(e) Use the Corporation's assets, directly or indirectly, for any purpose other than carrying on the Corporation's business.

(f) Wrongfully transfer or dispose of Corporation property, including intangible property such as goodwill.

(g) Use the Corporation's name (or any substantially similar name) or any trademark or trade name adopted by the Corporation, except on behalf of Corporation in the ordinary course of its business or as a reference to the Corporation or its region.

(h) Disclose any of Corporation's or Members' business practices, trade secrets, or any other confidential or proprietary information not generally known to the business community to any person not authorized to receive it.

Section 3. Loans and Guarantees. Neither participation in the activities of the Corporation nor any provision of these Bylaws or of the Certificate of Formation shall be deemed to constitute a pledge or loan of the credit of any Member for the benefit of the Corporation or a guarantee by any Member of any obligation of the Corporation.

ARTICLE XV.
BOOKS AND RECORDS; AUDIT; FISCAL YEAR

Section 1. Access to Books and Records. All Members of the Corporation will have access to the books and records of the Corporation, including financial statements and budgets; however, the Board shall establish procedures by which a Member, upon written

demand stating the purpose of the demand may examine and copy the books and records of the Corporation. If necessary to protect the confidential information of the Corporation, a Member requesting examination of any of the Corporation's non-public books and records will be required to sign a confidentiality and non-disclosure agreement before viewing such information. The procedures shall include policies that provide reasonable protection against the unnecessary disclosure of information related to individual employees, including their compensation.

Section 2. Audit. At least annually, an audit of the financial statements of the Corporation shall be performed by the Auditor approved by the Board. The Auditor's opinion and the audited financial statements will be made available to all Members as described in Article XV, Section 1.

Section 3. Fiscal Year. The fiscal year of the Corporation shall be from January 1 through the following December 31, unless otherwise established by resolution of the Board.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Monitoring System Conditions -	)	Docket Nos. RM13-12-000
Transmission Operations Reliability	)	RM13-14-000
Standard	)	RM13-15-000
Transmission Operations Reliability	)	
Standards	)	
Interconnection Reliability Operations and	)	
Coordination Reliability Standards	)	

NOTICE OF WITHDRAWAL OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Pursuant to Rule 216[1] of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or the "Commission"), the North American Electric Reliability Corporation ("NERC") hereby submits this notice of withdrawal of its changes to the Transmission Operations ("TOP") Reliability Standards and Interconnection Reliability Operations and Coordination ("IRO") Reliability Standards filed in Docket Nos. RM13-12-000,[2] RM13-14-000,[3] and RM13-15-000.[4]

I. Background

On November 21, 2013, the Commission issued a Notice of Proposed Rulemaking ("TOP/IRO NOPR")[5] proposing to approve TOP-006-3 and remand the revised TOP and IRO

[1] 18 C.F.R. § 385.216 (2014).

[2] On April 4, 2013, in Docket No. RM13-12-000, NERC proposed revisions to Reliability Standard TOP-006-3 to divide the reporting responsibilities of Balancing Authorities and Transmission Operators into separate requirements.

[3] On April 16, 2013, in Docket No. RM13-14-000, NERC submitted for Commission approval three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection and Control ("PRC") Reliability Standard, PRC-001-2 (System Protection Coordination) to replace the eight currently-effective TOP standards.

[4] On April 16, 2013, in Docket No. RM13-15-000, NERC submitted for Commission approval four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators).

[5] *Monitoring System Conditions- Transmission Operations Reliability Standard Transmission Operations Reliability Standards Interconnection Reliability Operations and Coordination Reliability Standards*, 145 FERC ¶ 61,158 (2013) ("TOP/IRO NOPR").

Reliability Standards. In the TOP/IRO NOPR, the Commission raised, among its concerns, that NERC "has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards."[6]

On December 20, 2013, NERC filed a motion requesting that the Commission defer action, until January 31, 2015, to allow NERC time to consider the reliability concerns raised by the Commission in the TOP/IRO NOPR and revise the proposed Reliability Standards as necessary. On January 14, 2014, the Commission granted NERC's motion to defer action.[7]

II. Notices and Communications

Notices and communications with respect to this filing may be addressed to the following:[8]

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III. Support for Withdrawal

Since the issuance of the TOP/IRO NOPR, NERC developed revisions to the TOP and IRO Reliability Standards in Project 2014-03, which were approved by the NERC Board of Trustees on November 13, 2014 and February 11, 2015. Concurrent with this Motion to

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[6] TOP/IRO NOPR at P 4.

[7] *Monitoring System Conditions - Transmission Operations Reliability Standard, Transmission Operations Reliability Standards, Interconnection Reliability Operations and Coordination Reliability Standards*, 146 FERC ¶ 61,023 (2014).

[8] Persons to be included on the Commission's service list are indicated with an asterisk. NERC requests waiver of 18 C.F.R. § 385.203(b) to permit the inclusion of more than two people on the service list.

Withdraw, these revised TOP and IRO Reliability Standards have been filed with the Commission.

IV. Conclusion

NERC requests that the Commission permit withdrawal of NERC's petitions, either by order or expiration of the fifteen (15) day period in Rule 16.

Respectfully submitted,

/s/ Shamai Elstein
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Counsel for the North American Electric Reliability Corporation

Dated: March 18, 2015

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of this submittal upon all parties listed on the official service lists compiled by the Secretary in this proceeding in Docket Nos. RM13-12-000, RM13-14-000, and RM13-15-000.

Dated at Washington, D.C. this 18th day of March, 2015.

/s/ Shamai Elstein

Shamai Elstein

Counsel for North American Electric Reliability Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RD15-1-000**

MOTION TO FILE LIMITED ANSWER OF
THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

On January 15, 2015, Dominion Resources Services, Inc. ("Dominion") filed a protest to the *Joint Petition for Approval of Proposed Regional Reliability Standards VAR-002-WECC-2 and VAR-501-WECC-2*, submitted by the North American Electric Reliability Corporation ("NERC") and the Western Electric Coordinating Council ("WECC").[1] By this submittal and pursuant to Rules 212[2] and 213[3] of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission"), NERC and WECC jointly move for leave to answer and briefly answer certain arguments and positions set forth in the Dominion protest.

I. Motion for Leave to Answer

Rule 213(a)(2)[4] of the Commission's Rules of Practice and Procedure prohibits an answer to a protest unless otherwise ordered by the decisional authority. However, the Commission often accepts answers to protests where an answer provides information that assists the Commission in the decision-making process.[5] The Commission has found good cause to permit answers where they are otherwise prohibited in various other circumstances, including

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1 *Joint Petition for Approval of Proposed Regional Reliability Standards VAR-002-WECC-2 and VAR-501-WECC-2*, Docket No. RD15-1-000 (Dec. 15, 2014) ("Joint Petition").
2 18 C.F.R. § 385.212 (2014).
3 *Id*. § 385.213.
4 *Id*. § 385.213(a)(2).
5 *See, e.g., ISO New England Inc. and New England Power Pool*, 142 FERC ¶ 61,024 at P 32 (2013); *PJM Interconnection, LLC*, 142 FERC ¶ 61,019 at P 23 (2013).

where a protestor has provided an inaccurate interpretation of the contents of a filing,[6] and where the answer would assure a complete record in the proceeding,[7] lead to a better understanding of the issues in the proceeding,[8] permit the issues to be narrowed or clarified,[9] and aid in the disposition of the issues raised by the protests.[10] NERC and WECC submit that its answer will help clarify the issues raised by Dominion, resulting in a complete and accurate record upon which the Commission may issue an order. Therefore, NERC and WECC jointly move for leave to answer Dominion's protest of the Joint Petition.

II. Background

On December 15, 2014, NERC requested approval of proposed regional Reliability Standards VAR-002-WECC-2 and VAR-501-WECC-2. Proposed VAR-002-WECC-2 and proposed VAR-501-WECC-2 each revise currently effective version 1 standards to remove an administrative Requirement.

On January 15, 2015, Dominion filed its protest to the Joint Petition. Of note, Dominion is not registered in the WECC Regional Entity footprint. No comments were submitted by other entities. In its protest, Dominion states that it does not oppose the Joint Petition, but expresses concerns that the proposed regional Reliability Standards do not include a waiver or variance from the "equivalent" continent-wide standard or are not incorporated as specific requirements (applicable only within that region) into the continent-wide standard. Dominion contends that

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6 *See, e.g., Alliance Cos., et al.*, 91 FERC ¶ 61,152 at pp. 61,577-78 (2000)

7 *See, e.g., High Island Offshore System, L.L.C.*, 113 FERC ¶ 61,202 at P 8 (2005).

8 *See, e.g., Mississippi River Transmission, LLC*, 141 FERC ¶ 61,080 at P 4 (2012); *N.Y. Indep. Sys. Operator, Inc.*, 91 FERC ¶ 61,218, at 61,797 (2000) (allowing an answer deemed "useful in addressing the issues arising in these proceedings").

9 *See, e.g., TransColorado Gas Transmission Co.*, 111 FERC ¶ 61,208 at P 4 (2005); *PJM Interconnection, LLC*, 84 FERC ¶ 61,224, at p. 62,078 (1998); *Cent. Hudson Gas & Elec. Corp.*, 88 FERC ¶ 61,138, at 61,381 (1999) (accepting otherwise prohibited pleadings because they helped to clarify complex issues).

10 *See, e.g., Transcontinental Gas Pipe Line Co., LLC*, 140 FERC ¶ 61,251 at fn. 6 (2012).

the proposed WECC regional Reliability Standards are not more stringent[11] than the "equivalent" continent-wide Reliability Standard, VAR-002-3 and that the Commission should not approve the proposed regional Reliability Standards. Dominion requests that if VAR-002-WECC-2 receives FERC approval, the Commission should clarify that the Generator Operator can deem the exclusions in R1.1 through R1.10 in VAR-002-WECC-2 to be the equivalent of being exempted by the Transmission Operator as allowed in the continent-wide standard VAR-002-3 Requirement R1. Similarly, Dominion also requests that if VAR-501-WECC-2 receives FERC approval, that the Commission make clear that the Generator Operator can apply the exclusions listed in R1.1 through R1.12 when determining its compliance with VAR-002-3 Requirements R1 and R3. Dominion further requests that the Commission consider implementation of a waiver or variance from a continent-wide standard when there is a regional Reliability Standard that addresses the same subject matter.

III. Answer

Both NERC and WECC disagree with Dominion's assertions regarding the proposed regional Reliability Standards. Ruling in accordance with Dominion's comments, either to not approve the proposed regional Reliability Standards or to grant a waiver, would contradict prior

[11] NERC notes that Dominion erroneously summarizes the Commission's position in Order No. 672 with respect to acceptance of regional Reliability Standards. Dominion states that the Commission provided only two circumstances under which it would accept regional standards. *See* Dominion Protest at Section V.A. In fact, the Commission stated that "[a]s a general matter, we will accept the following two types of regional differences." *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 291, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006). While the Commission stated that regional differences will generally fall into two categories, the Commission did not rule out the possibility that there may be other circumstances that warrant acceptance of a regional Reliability Standard.

Commission precedent in Order No. 751, which approved VAR-002-WECC-1 and VAR-501-WECC-1.[12] In that order, the Commission made the following determination:

> [w]e approve Reliability Standards FAC-501-WECC-1, PRC-004-WECC-1, VAR-002-WECC-1, and VAR-501-WECC-1 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. We find that the revised WECC Reliability Standards are more stringent than the corresponding NERC Reliability Standards either because they address issues not covered in the requirements of the corresponding NERC Reliability Standards or because they offer more detailed requirements than the corresponding NERC Reliability Standards. For these same reasons, we find that the requirements of these revised regional Reliability Standards are not redundant of the requirements of the corresponding NERC Reliability Standards.[13]

The Commission further found that, because the VAR-002-WECC-1 standard specifies the circumstances in which a Generator Operator or Transmission Operator is excused from operating with automatic voltage regulator in-service and in automatic voltage control mode, Requirement R1 of VAR-002-WECC-1 is therefore more stringent than the requirement in VAR-002-1.1b.[14] The Commission also specifically ruled that the regional Reliability Standard VAR-002-WECC-1 and the continent-wide Reliability Standard should both apply. The Commission stated:

> [e]ven with the additional stringency of the regional Reliability Standard, generator operators must still comply with the requirements of NERC VAR-002-1.1b, which requires generators with automatic voltage regulators to operate each generator in the automatic voltage control mode unless the generator operator has notified the transmission operator.[15]

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[12] *See Version One Regional Reliability Standards for Facilities Design, Connections, and Maintenance; Protection and Control; and Voltage and Reactive*, Order No. 751, 135 FERC ¶ 61,061 (2011) (approving VAR-002-WECC-1 and VAR-005-WECC-1).

[13] Order No. 751 at P 11.

[14] *Id.* at P 58 (summarizing the Commission's technical position in the NOPR comparing the regional and continent-wide Reliability Standards).

[15] *Id*. at P 72.

Ruling in accordance with Dominion's comments would also conflict with subsequent Commission orders[16] that approved revised versions of the continent-wide VAR-002. These orders did not identify a conflict between the proposed version of VAR-002 or a concern regarding the additional stringency in the Commission-approved regional Reliability Standards. For example, on November 21, 2012, NERC submitted a petition requesting approval of VAR-002-2b (*Generator Operation for Maintaining Network Voltage Schedules*), which included a limited change to address a request for interpretation. In the April 16, 2013 order approving VAR-002-2b, the Commission did not direct any changes or raise any issues with respect to the stringency of the VAR-002-WECC-1 standard.[17] .

Similarly, on June 9, 2014, NERC sought Commission approval of Reliability Standards VAR-001-4 (*Voltage and Reactive Control*) and VAR-002-3 (*Generator Operation for Maintaining Network Voltage Schedules*), which were approved by delegated letter order on August 1, 2014.[18] In the proceeding to approve VAR-002-3, neither the Commission nor commenters in the proceeding cited a conflict between or an issue regarding the additional stringency in regional Reliability Standards VAR-002-WECC-1 and VAR-501-WECC-1. In fact, the standard development record for VAR-002-3 did not include any comments regarding either VAR-002-WECC-1 or VAR-501-WECC-1.[19]

In the interest of clarity, NERC and WECC provide the following examples where the proposed regional Reliability Standards continue to be more stringent than VAR-002-3. VAR-002-3 Requirement R1 allows the automatic voltage regulator to be operated in a mode other

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16 *See* infra for specific order citations and explanation.

17 *N. Am. Elec. Reliability Corp.*, 143 FERC ¶ 61,045 (2013).

18 *N. Am. Elec. Reliability Corp.*, Docket No. RD14-11-000 (Aug. 1, 2014) (unpublished delegated letter order).

19 *See Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standards VAR-001-4 and VAR-002-3 and the Retirement of Reliability Standards VAR-001-3 and VAR-002-2b*, Docket No. RD14-11-000 (Jun. 9, 2014).

than voltage control mode as long as the Generator Operator notifies the Transmission Operator. Proposed VAR-002-WECC-2 does not have this allowance. The proposed regional Reliability Standard continues to limit the time the automatic voltage regulator is not in voltage control mode to 2% of the time. The language of VAR-002-3 does not place any limit on the amount of time that a generator could be operated in a mode other than automatic voltage control mode. Similarly, proposed VAR-501-WECC-2 requires power system stabilizers to be in operation 98% of the time with a very limited set of exclusions to arrive at the 98% in-service target. VAR-002-3 only requires that the Generator Operator notify its associated Transmission Operator of a change in status. As a result, both proposed Reliability Standards continue to contain elements that are more stringent than the continent-wide Reliability Standard VAR-002-3.

In summary, the Commission has already ruled on the increased stringency of the regional Reliability Standards over the comparable continent-wide Reliability Standard. NERC and WECC's proposed deletions do not change the technical coverage of the proposed regional Reliability Standard and, therefore, the regional Reliability Standards continue to be more stringent than the continent-wide Reliability Standards. As a result, the Commission should approve the proposed regional Reliability Standards as filed. The Commission should deny Dominion's request in its entirety including its request for future waivers.

If there is a legitimate concern regarding a regional Reliability Standard and a continent-wide Reliability Standard, the proper place, in the first instance, to raise the concern is the NERC or WECC standard development processes. Because Dominion raises these concerns for the first time[20] in this proceeding with respect to these particular regional Reliability Standards, the

[20] *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672 at P 334, FERC Stats. &

Commission should not take the action requested by Dominion and act on the Joint Petition as filed.

Respectfully submitted,

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February 26, 2015

Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006) ("we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by the Commission.").

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C., this 26th day of February, 2015.

/s/ Sean Bodkin

Counsel for the North American Electric Reliability Corporation

150 FERC ¶ 61,212
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Cheryl A. LaFleur, Chairman;
Philip D. Moeller, Tony Clark,
Norman C. Bay, and Colette D. Honorable.

North American Electric Reliability Corporation Docket No. NP15-1-000

ORDER ON REVIEW OF NOTICE OF PENALTY

(Issued March 19, 2015)

1. On October 30, 2014, the North American Electric Reliability Corporation (NERC) submitted a Notice of Penalty filing to the Commission, assessing a $52,000 penalty against NextEra Energy Resources, LLC (NextEra) for violations of Reliability Standards under section 215(e) of the Federal Power Act (FPA).[1] According to the Notice of Penalty, NextEra's failure to timely reduce the output of a generator pursuant to an out of merit energy instruction issued by a reliability coordinator, the Electric Reliability Council of Texas, Inc. (ERCOT), violated the provisions of two Reliability Standards that require an entity to comply with directives or reliability directives issued by a reliability coordinator.[2] NextEra filed an application with the Commission for review of the Notice of Penalty on November 26, 2014. NextEra asks the Commission to find that NextEra did not receive such a directive pursuant to mandatory Reliability Standards and, accordingly, to reverse the NERC Notice of Penalty.

2. In this order, the Commission finds that NextEra violated two Reliability Standards by failing to timely comply with such a directive. Further, the Commission is not persuaded by other substantive and procedural arguments provided by NextEra, as

[1] 16 U.S.C. § 824o(e) (2012).

[2] The NERC Glossary of Terms Used in Reliability Standards defines "reliability coordinator" as "[t]he entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. . . ."

discussed below. Accordingly, the Commission affirms the $52,000 penalty assessed by NERC.

I. Background

A. Section 215 of the Federal Power Act

3. Section 215 of the FPA authorizes the Commission to certify and oversee an electric reliability organization (ERO) responsible for developing and enforcing mandatory Reliability Standards that are applicable to users, owners and operators of the Bulk-Power System.[3] Exercising this statutory authority, the Commission certified NERC as the ERO in 2006.[4] As contemplated under FPA section 215(e)(4), NERC has delegated certain oversight and enforcement authority to eight Regional Entities, including the Texas Reliability Entity, Inc. (Texas RE), which has enforcement and oversight responsibility for NextEra relevant to this proceeding.[5]

4. Pursuant to FPA section 215(e)(1), NERC as the ERO has the authority to "impose . . . a penalty on a user or owner or operator of the bulk-power system for a violation of a reliability standard approved by the Commission."[6] NERC and the Regional Entities to which NERC delegates compliance and enforcement authority identify potential violations using various compliance tools, including audits, spot checks, investigations, required self-certifications, and voluntary self-reporting.

5. The FPA and Commission regulations require NERC to file a Notice of Penalty with the Commission before a penalty that NERC or a Regional Entity assesses for a violation of a Reliability Standard can take effect.[7] Each such penalty determination is

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[3] 16 U.S.C. § 824o.

[4] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062 (ERO Certification Order), *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,190, *order on reh'g*, 119 FERC ¶ 61,046 (2007), *rev. denied sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[5] *See North American Electric Reliability Corp.*, 119 FERC ¶ 61,060, *order on reh'g*, 120 FERC ¶ 61,260 (2007).

[6] 16 U.S.C. § 824o(e)(1).

[7] 16 U.S.C. § 824o(e)(1), (2); *see also Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs.

(continued ...)

subject to Commission review, either on the Commission's own motion or by application for review by the recipient of the penalty, within thirty days from the date NERC files the applicable Notice of Penalty.[8] In the absence of an application for review of a penalty or other action by the Commission, each penalty filed by NERC is affirmed by operation of law upon the expiration of the applicable thirty-day period.[9]

B. Reliability Standards IRO-001-1 and TOP-001-1

6. In Order No. 693, the Commission approved 83 Reliability Standards as mandatory and enforceable, pursuant to FPA section 215(d).[10] Relevant to the immediate proceeding, the Commission, in Order No. 693, approved two Reliability Standards that pertain to compliance with reliability directives issued by a reliability coordinator. First, Reliability Standard IRO-001-1 (Reliability Coordination – Responsibilities and Authorities) has the following stated purpose: "Reliability Coordinators must have the authority, plans, and agreements in place to immediately direct reliability entities within their Reliability Coordinator Areas to re-dispatch generation, reconfigure transmission, or reduce load to mitigate critical conditions to return the system to a reliable state." Requirement R8 of Reliability Standard IRO-001-1 requires applicable entities to comply with directives issued by the reliability coordinator or notify the reliability coordinator of an inability to comply with directives, as follows:

> Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.

¶ 31,204 at P 506, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[8] 16 U.S.C. § 824o(e)(2).

[9] 16 U.S.C. § 824o(e)(2).

[10] *Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order or reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

7. Second, Reliability Standard TOP-001-1 (Reliability Responsibilities and Authorities) has the following stated purpose: "To ensure reliability entities have clear decision-making authority and capabilities to take appropriate actions or direct the actions of others to return the transmission system to normal conditions during an emergency." Requirement R3 of Reliability Standard TOP-001-1, likewise, sets out the requirement to comply with reliability directives as follows:

> Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements.

II. NERC Notice of Penalty Filing and Stipulated Facts

A. Parties

8. NextEra, a subsidiary of FPL Group, Inc., owns or controls generation facilities in 24 states. In the Texas RE region, NextEra is registered on the NERC compliance registry as the generator owner and generator operator for two natural gas fired generation sites as well as numerous wind powered generation sites, with a total nameplate rating of approximately 5,189 MW. NextEra is the entity responsible for responding to the out of merit energy instructions issued by ERCOT, which is registered on the NERC compliance registry as the reliability coordinator and transmission operator for the Texas RE region.[11]

9. As mentioned above, Texas RE is a Regional Entity under a delegation agreement between NERC and Texas RE pursuant to section 215(e)(4) of the FPA. Headquartered in Austin, Texas RE is a non-profit corporation that has delegated oversight and enforcement authority for the ERCOT region.

[11] *See* Notice of Penalty Att. B-7.vi (Texas Commission Joint Stipulated Facts) at 1 (defining out of merit energy as "Energy provided by a Resource selected by ERCOT outside the bidding process to resolve a reliability or security event").

B. Stipulated Facts

10. In the proceeding before the Commission, as well as in the underlying NERC, Texas RE, and Public Utility Commission of Texas (Texas Commission) proceedings, the parties stipulated the following facts.[12]

11. At 11:29 a.m. on October 12, 2008, ERCOT issued a written electronic out of merit energy instruction to NextEra instructing NextEra to reduce the output of one of its wind generation stations to zero MW.[13] ERCOT issued the out of merit energy instruction to NextEra to address an overloading transmission line. NextEra did not reduce the output as instructed within one hour.[14] At 12:14 p.m., ERCOT issued an "Operating Constraint Limit 1" (OC1), a zonal congestion management tool redirecting generation within certain zones, to maintain system stability limits. At 12:28 p.m., ERCOT deactivated the OC1 because other generators reduced their output at ERCOT's direction.

12. At 12:59 p.m., an ERCOT operator called the NextEra operator and asked whether the NextEra operator had seen the out of merit energy instruction. The NextEra operator stated that he did not see the out of merit energy instruction and that he would now comply.[15] At 1:04 p.m., an ERCOT shift supervisor called the NextEra operator to ask why the NextEra operator had not followed the out of merit energy instruction. The NextEra operator stated that he did not comply with the out of merit energy instruction because he was busy and missed the out of merit energy instruction.[16] The ERCOT shift supervisor informed the NextEra operator that if NextEra had complied with the out of merit energy instruction when ERCOT issued it, ERCOT probably would not have had to issue the OC1.[17] At 1:13 p.m., NextEra reduced the generator output as instructed in the out of merit energy instruction.

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[12] *See* Notice of Penalty, Att. B-7.vi (Texas Commission Joint Stipulated Facts).

[13] *Id.* at 1. ERCOT protocols require entities to acknowledge receipt of an out of merit energy instruction within one hour.

[14] *Id.* at 1.

[15] *Id.* at 2.

[16] *Id.*

[17] *Id.*

C. Texas RE Proceedings

13. Following a "spot check" investigation, on February 22, 2011, Texas RE issued a notice of alleged violation, alleging that NextEra violated Reliability Standards IRO-001-1 Requirement R8 and TOP-001-1 Requirement R3 by failing to comply with the ERCOT out of merit energy instruction on October 12, 2008.[18] Texas RE recommended assessing a monetary penalty of $52,000 for the violations ($21,000 for violating Reliability Standard IRO-001-1 and $31,000 for violating Reliability Standard TOP-001-1). Pursuant to Texas RE's rules at that time, NextEra filed a complaint with the Texas Commission, then the hearing body for Texas RE, challenging the Texas RE allegations.[19]

14. On November 15, 2012, the Texas Commission issued a final recommendation concluding that: (1) NextEra violated Reliability Standard IRO-001-1 Requirement R8; (2) the out of merit energy instruction was a directive as the term is used in in IRO-001-1 Requirement R8; (3) no penalty should be imposed on NextEra because it did not know and reasonably should not have known that its failure to comply with the out of merit energy instruction would constitute a violation of a Reliability Standard; (4) NextEra did not violate Reliability Standard TOP-001-1 Requirement R3 because there was no declared emergency in effect at the time ERCOT issued the out of merit energy instruction; and (5) if Texas RE imposed a penalty contrary to the Texas Commission final recommendation, the penalty should not exceed $21,000 for the violation of Reliability Standard IRO-001-1.[20] Pursuant to the Texas RE rules, Texas RE compliance staff appealed the Texas Commission Final Recommendation Order to the Texas RE board of directors (Texas RE Board).

15. On January 17, 2013, the Texas RE Board issued a decision (Texas RE Board Decision) following a *de novo* review of the Texas Commission Final Recommendation Order.[21] The Texas RE Board reversed the Texas Commission Final Recommendation

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[18] Notice of Penalty, Att. A.b. (Texas RE Notice of Alleged Violation).

[19] Notice of Penalty, Att. B-2.i (NextEra Complaint). Subsequently, the Texas RE delegation agreement was revised so that the Texas RE directors act as the hearing body. *North American Electric Reliability Corporation*, Docket No. RR13-7-000 (Aug. 19, 2013) (delegated letter order).

[20] Notice of Penalty, Att. B-12.iii (Texas Commission Final Recommendation Order).

[21] Notice of Penalty, Att. B-13.i (Texas RE Board Decision).

Order and found that a monetary penalty of $52,000 was appropriate. The Texas RE Board concluded among other things that: (1) ERCOT's out of merit energy instruction constituted a directive and reliability directive under Reliability Standards IRO-001-1 Requirement R8 and TOP-001-1 Requirement R3, respectively; (2) NextEra knew or should have known that its failure to comply with the out of merit energy instruction would violate the Reliability Standards; (3) Reliability Standard TOP-001-1 Requirement R3 applies in the absence of system emergencies; and (4) the appropriate penalty for NextEra's violations is $52,000.[22] NextEra appealed the Texas RE Board Decision to the NERC Board of Trustees Compliance Committee (Compliance Committee).

D. NERC Compliance Committee Decision and Notice of Penalty

16. On July 15, 2014, the NERC Compliance Committee issued a Decision on Appeal of Violation Determination (Compliance Committee Decision) upholding the Texas RE Board Decision.[23] The Compliance Committee Decision addressed fourteen claims of error by NextEra regarding the Texas RE Board's determination and concluded that, "[a]fter engaging in a reasoned analysis of the arguments and evidence before it, the NERC Compliance Committee affirms the Decision of the Texas RE Board."[24] The Compliance Committee decision upheld the Texas RE Board determinations that NextEra violated Reliability Standards IRO-001-1 and TOP-001-1 because the ERCOT out of merit energy instruction was a directive and a reliability directive and that Reliability Standard TOP-001-1 applies in non-emergency situations. The Compliance Committee Decision also addressed NextEra's claims of procedural errors.

17. NERC submitted a Notice of Penalty to the Commission on October 30, 2014, assessing a $52,000 penalty against NextEra for violations of Reliability Standards IRO-001-1 (Reliability Coordination — Responsibilities and Authorities) Requirement R8 and TOP-001-1 (Reliability Responsibilities and Authorities) Requirement R3.

III. NextEra Application for Review of Notice of Penalty

18. On November 26, 2014, as amended on December 17, 2014, NextEra filed an Application for Review of Penalty asking the Commission to review the NERC Notice of Penalty and "set aside" the penalty because NERC and the Texas RE Board "failed to

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[22] *Id.* at 25.

[23] Notice of Penalty, Att. B-16.vi (NERC Compliance Committee Decision).

[24] *Id.* at 10.

meet their burden demonstrating that reliability violations have in fact occurred.[25] NextEra states that it is challenging the assessment of the $52,000 penalty because it believes that the out of merit energy instruction ERCOT issued does not constitute a directive or a reliability directive pursuant to Reliability Standards IRO-001-1 Requirement R8 or TOP-001-1 Requirement R3, respectively.

19. NextEra states that it "has never denied that its operator failed to respond timely to ERCOT's [out of merit energy] instruction" issued on October 12, 2008, and that "failing to respond . . . violated ERCOT Protocol 5.4.4."[26] Rather, NextEra challenges whether the fact that the NextEra operator failed to respond timely to the ERCOT out of merit energy instruction automatically constitutes a violation of Reliability Standards IRO-001-1 Requirement R8 and TOP-001-1 Requirement R3. NextEra argues that the ERCOT out of merit energy instruction is not a directive or a reliability directive pursuant to the two Reliability Standards.[27] NextEra asserts that, for Reliability Standards IRO-001-1 or TOP-001-1 to apply, ERCOT should have identified the out of merit energy instruction as a directive or reliability directive using three-part communication.[28] According to NextEra, it has received out of merit energy instructions pursuant to ERCOT's market protocols, but had no real or constructive knowledge that the out of merit energy instruction constituted a directive or reliability directive pursuant to Reliability Standards IRO-001-1 or TOP-001-1.

20. Further, NextEra argues that NERC erred by failing to find that Reliability Standard TOP-001-1 Requirement R3 is limited to emergencies, as suggested by the purpose statement of the standard. NextEra also contends that the NERC Compliance Committee erred procedurally: (1) by effectively eliminating the burden of persuasion from the Texas RE compliance staff; (2) in accepting parol evidence provided by a Texas RE board member; (3) by failing to ensure consistent interpretation of Reliability Standards by all Regional Entities; and (4) by applying an erroneous standard of review to the Texas RE Board Decision.

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[25] NextEra Application at 1.

[26] *Id.* at 2.

[27] *Id.* at 3.

[28] *Id.* at 6.

IV. Order Initiating Review and Responsive Pleadings

21. On November 28, 2014, the Commission issued an Order Initiating Review of the Notice of Penalty.[29] The Commission established a filing deadline of December 18, 2014 for submission of answers, interventions or comments. NERC filed an answer to NextEra's application for review. Texas RE and Trade Associations[30] filed timely motions to intervene and comments. On January 15, 2015, NextEra filed a motion for leave to answer and answer. Exelon Corporation filed a timely motion to intervene.

A. NERC Answer

22. NERC answers that: (1) the undisputed facts in the record provide ample support for the determination of the NERC Compliance Committee; (2) the NERC Compliance Committee correctly found that NextEra violated Reliability Standards IRO-001-1 Requirement R8 and TOP-001-1 Requirement R3; and (3) at all stages of the proceedings, NextEra was afforded proper due process.

23. NERC avers that the record evidence demonstrates that ERCOT regularly used out of merit energy instructions to give direction to market participants in the ERCOT region.[31] NERC argues that, while "directive" was not a defined NERC term at the time of the incident, the out of merit energy instruction was clearly a directive within the common meaning of the word, i.e., "an order or instruction, particularly from a central authority."[32] NERC contends that both the plain meaning and the context in which the term directive appears in Reliability Standards IRO-001-1 and TOP-001-1 support the NERC Compliance Committee conclusion that ERCOT issued a directive for the purposes of those Reliability Standards when it issued the out of merit energy instruction to NextEra.[33] Noting that NextEra does not dispute that the out of merit energy instruction contained clear instructions regarding the actions ERCOT expected NextEra

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[29] *North American Electric Reliability Corp.*, 149 FERC ¶ 61,186 (2014).

[30] Trade Associations include the Edison Electric Institute (EEI), the American Public Power Association (APPA), the National Rural Electric Cooperative Association (NRECA), and the Electric Power Supply Association (EPSA).

[31] NERC Answer at 2.

[32] *Id.* at 8 (quoting NERC Compliance Committee Decision at 27 and *The American Heritage Dictionary of the English Language* (5th ed. 2014)).

[33] *Id.* at 8.

to take, NERC cites the definition of "Out of Merit Energy" indicating that ERCOT issued out of merit energy instructions for reliability purposes.[34] NERC adds that ERCOT issued the out of merit energy instruction to address transmission line overloading, which is a reliability issue.

24. Regarding NextEra's argument that it did not violate Reliability Standard TOP-001-1, NERC contends that the purpose statement of a Reliability Standard serves as a general guideline and not as an enforceable requirement.[35] NERC also notes that some of the Requirements within Reliability Standard TOP-001-1 include specific language indicating that they apply "during a system emergency," while other Requirements are not similarly qualified.

B. Comments

25. Texas RE supports NERC's response and emphasizes that NextEra has never disputed the fact that its operator failed to timely respond to an out of merit energy instruction from ERCOT.[36] Texas RE adds that the Texas RE Board and the NERC Compliance Committee weighed the evidence and determined that the violations and penalty in the docket are appropriate. Further, Texas RE expresses concern that, "[i]f registered entities can escape responsibility for compliance with directives by making post-hoc claims regarding ambiguity when there is no indication of any real-time ambiguity or confusion, Texas RE is concerned that the task of assuring the reliability of the electric grid may be unnecessarily complicated and reliability compromised."[37]

26. Trade Associations urge the Commission to reverse the NERC Compliance Committee Decision and, in doing so, address the due process issues raised by NextEra.[38] Trade Associations claim that many registered entities with process issues similar to

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[34] *Id.* at 9 (quoting NERC Compliance Committee Decision at 12 (defining "Out of Merit Energy" as energy provided by a generator "outside the bidding process to resolve a reliability or security event")).

[35] *Id.* at 12.

[36] Texas RE Comments at 3-5.

[37] *Id.* at 5.

[38] Trade Associations Comments at 4.

those described by NextEra have agreed to settlements rather than pursue a lengthy and expensive appeal process.[39]

27. Trade Associations reiterate NextEra's alleged procedural infirmities. Trade Associations argue that the record of the original Texas RE investigation is flawed because Texas RE did not contact ERCOT when gathering evidence to determine the ERCOT operator's intent when issuing the out of merit energy instruction. Trade Associations contend that the nature of a dispatch instruction or two-way communication involving actionable requirements should be made clear at the time it occurs. Trade Associations also argue that the NERC Compliance Committee erred in applying an "arbitrary and capricious" standard of review for the Texas RE Board Decision and, rather, should have conducted a *de novo* review of the underlying decision.[40] Further, Trade Associations contend that parol evidence is not acceptable in enforcement matters. Trade Associations express concern that the NERC Compliance Committee's use of statutory interpretation principles for "unambiguous" purpose statements may render the purpose statements meaningless, and further argue that NERC should consistently interpret purpose statements in order to satisfy due process requirements.[41]

C. NextEra Answer

28. In its answer, NextEra argues that the Commission should not "brush aside" the procedural due process concerns that it raises in its application for review because failure to adhere to proper procedural due process will undermine enforcement of Reliability Standards.[42] NextEra contends that communications made pursuant to market protocols should not be treated as communications made pursuant to the Reliability Standards absent additional evidence. Finally, NextEra argues that NERC's analysis defining the term "directive" was incomplete because Texas RE compliance staff did not meet their burden of persuasion, which should have included interviewing ERCOT staff.[43]

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[39] *Id.*

[40] *Id.* at 6-7.

[41] *Id.* at 7-9.

[42] NextEra Answer at 3.

[43] *Id.* at 8-9.

V. Discussion

A. Procedural Matters

29. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure,[44] the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

30. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure[45] prohibits an answer to a protest unless otherwise ordered by the decisional authority. We will accept NextEra's answer because it has provided information that assisted us in our decision-making process.

B. Commission Determination

31. Pursuant to section 215(e)(2) of the FPA and section 39.7 of the Commission's regulations, the Commission affirms the $52,000 penalty assessed by NERC.[46] As explained below, we find that the out of merit energy instruction issued by ERCOT constitutes a directive and reliability directive pursuant to Reliability Standards IRO-001-1 Requirement R8 and TOP-001-1 Requirement R3, respectively. We further find that NextEra's failure to respond timely to the ERCOT out of merit energy instruction resulted in a violation by NextEra of Reliability Standards IRO-001-1 Requirement R8 and TOP-001-1 Requirement R3. Below, we discuss our findings that NERC: (1) reasonably concluded that NextEra violated Reliability Standards IRO-001-1 Requirement R8 and TOP-001-1 Requirement R3, (2) reasonably interpreted Reliability Standard TOP-001-1 to apply in certain non-emergency situations, and (3) provided adequate procedural due process to NextEra.

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[44] 18 C.F.R. § 385.214 (2014).

[45] 18 C.F.R. § 385.213(a)(2) (2014).

[46] *See* 16 U.S.C. § 824o(e)(2); 18 C.F.R. § 39.7 (2014).

1. NERC Reasonably Concluded that ERCOT Issued a Directive for Purposes of the Reliability Standards in Effect When the Incident Occurred

a. NERC Compliance Committee Decision

32. In its July 2014 Decision, the NERC Compliance Committee found that the ERCOT out of merit energy instruction was a directive and reliability directive under Reliability Standards IRO-001-1 Requirement R8 and TOP-001-1 Requirement R3, respectively. The Compliance Committee adopted the following rationale of the Texas RE Board:

> The language and context of IRO-001-1 R8 are sufficient to support the [Texas Commission]'s conclusion that the [out of merit energy instruction] was a directive. Moreover, the definition of [out of merit energy] is energy provided by a generator "outside the bidding process to resolve a reliability or security event," which indicates that ERCOT issues [out of merit energy instructions] for reliability purposes. The stated purpose of IRO-001-1 is to ensure that Reliability Coordinators have the authority to direct reliability entities to take the actions needed to return the system to a reliable state. Requirement 8 makes clear that directives are the means for Reliability Coordinators to exercise this authority. The [out of merit energy instruction] issued at 11:29 [AM CST] on October 12, 2008 clearly required NextEra to reduce the output of Capridge 4 to 0 MW by 12:00 [PM CST], and the parties stipulate that an [out of merit energy instruction] was issued to address overloading of the San Angelo-Menard transmission line. The [out of merit energy instruction] meets the plain meaning of directive, and falls within the context of IRO-001-1 as it was issued by ERCOT to return the system to a reliable state within normal operating limits.[47]

33. Further, the NERC Compliance Committee disagreed with the Texas RE Board regarding the relevance of the operator's intent and found "that whether the operator intended the [out of merit energy instruction] to be a directive pursuant to a Reliability Standard is irrelevant to a determination of whether NextEra failed to comply with the Standard."[48] The NERC Compliance Committee also explained that:

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[47] NERC Compliance Committee Decision at 12 (quoting Notice of Penalty, Att. B-13.i (Texas RE Board Decision) at 8).

[48] *Id.* at 19.

> The Texas RE Board did not rely on the intent of the ERCOT operator. Rather, the Texas RE Board relied on evidence in the record, including evidence that NextEra frequently received [out of merit energy instructions] and complied with them without raising concerns about their legal implications. . . . In addition, the Texas RE Board cited the ERCOT Reliability Plan in effect at the time and the fact that the Plan makes clear that ERCOT, as the Reliability Coordinator for its region, has the authority to direct generators to take actions to ensure reliable operations.[49]

34. In addition, the NERC Compliance Committee distinguished between an electronic dispatch instruction like the October 12, 2008 out of merit energy instruction and a verbal directive under the ERCOT Protocols. The NERC Compliance Committee concluded that "the recipient of the [out of merit energy] order is not required to repeat back immediately what is contained in the written instruction."[50]

b. NextEra Application

35. NextEra argues that NERC erred in finding that the out of merit energy instruction was a directive and reliability directive pursuant to Reliability Standards IRO-001-1 and TOP-001-1, respectively. NextEra asserts that a reliability coordinator "must *intend* a communication–in this case, the electronic [out of merit energy] dispatch instruction–to be a directive or reliability directive."[51] According to NextEra, Texas RE's investigation of the underlying incident was flawed, in part, because Texas RE failed to investigate (or provide evidence at hearing of) the ERCOT operator's intent in issuing the directive.[52] Similarly, NextEra alleges that the NERC Compliance Committee erred in finding that the ERCOT operator's intent is irrelevant and argues that the NERC Compliance Committee "appears to argue that even if the ERCOT operator never intended to issue a directive . . . NERC can override ERCOT's intent and interpret the [out of merit energy]

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[49] *Id.* at 20-21 (footnotes omitted).

[50] *Id.* at 23.

[51] NextEra Application at 18 (emphasis in original).

[52] *Id.* at 19, 22. NextEra contends that Texas RE had the burden of persuasion to demonstrate the ERCOT operator's intent but failed to offer any evidence on the issue. NextEra suggests that, while not dispositive, an Incident Report provided by ERCOT to Texas RE regarding the October 12, 2008 events creates ambiguity regarding the ERCOT operator's intent since the report identified a possible ERCOT Protocol violation, and left blank the report section on possible NERC Reliability Standards violations. *Id.* at 19.

instruction to be a directive. . . ."[53] Further, NextEra contends that the Texas RE and NERC Compliance Committee erred in relying on evidence that "NextEra frequently received [out of merit energy instructions] and complied with them without raising concerns. . . ," since compliance with an instruction "simply means that the [NextEra] operator acted in a manner consistent with ERCOT Protocols and good utility practice."[54]

36. NextEra also argues that the Texas RE investigation was flawed because Texas RE's lead investigator was relatively new to Texas RE in 2010, received less than a week of training before being assigned to the NextEra investigation, and was not involved in evaluating NERC Reliability Standards in 2008 when the incident occurred. NextEra also faults Texas RE investigative staff for failing to consider a July 2009 memorandum from NERC stating its views on the proper communication of directives.

37. In addition, NextEra contends that ERCOT Power Operations Bulletin No. 388, which was in effect at the time of the incident at issue here, makes clear that an out of merit energy dispatch instruction is not a directive in ERCOT. According to NextEra, the bulletin repeatedly states that "all directives shall be in a clear, concise, and definitive manner. Ensure the recipient of the directive repeats the information back correctly. Acknowledge the response as correct or repeat the original statement to resolve any misunderstandings."[55] NextEra claims that the Texas RE compliance staff sought to limit the applicability of the bulletin by claiming that it applies only to verbal communications. NextEra states that the Commission should find that, had ERCOT issued a directive or reliability directive through the out of merit energy instruction, ERCOT procedures for issuing directives required ERCOT operators to employ three-part communications. NextEra argues that, because this did not occur, ERCOT did not issue a directive or reliability directive.[56] According to NextEra, the bulletin is particularly informative because the out of merit energy instruction was issued pursuant to ERCOT Protocol 5.4.4, which does not itself address the issuance of directives. NextEra also argues that, even if the NERC Compliance Committee properly interpreted the definition of directive and reliability directive, the NextEra operator could not have reasonably known of that interpretation at the time ERCOT issued the out of merit energy instruction.

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[53] *Id.* at 19-20.

[54] *Id.* at 20 (quoting NERC Compliance Committee Decision at 20-21).

[55] *Id.* at 23-24 (quoting Notice of Penalty, Att. B-7(iii), Exh. NEE-12).

[56] *Id.* at 24.

38. Further, NextEra takes exception with the Texas RE Board reasoning that "[n]either IRO-001-1 nor TOP-001-1 requires that directives be issued in a particular manner."[57] NextEra argues that ERCOT should have used three-part communication pursuant to Reliability Standard COM-002-2 (Communication and Coordination) Requirement R2 if the out of merit energy instruction was in fact a directive pursuant to IRO-001-1 and TOP-001-1.[58] Likewise, NextEra claims that NERC erred in concluding that "the preponderance of the evidence supports the conclusion that the October 12, 2008 [out of merit energy] instruction was a directive regardless of whether three-part communication was required by ERCOT and NextEra."[59] NextEra argues that, based on this rationale, "since ERCOT failed to employ three-part communications NextEra should have been omniscient and realized ERCOT intended the [out of merit energy] instruction to be a directive."[60]

c. NERC Answer and Comments

39. In its answer to NextEra, NERC contends that, in determining that the out of merit energy instruction was a directive, the Texas RE Board and the NERC Compliance Committee applied the plain, ordinary meaning of the word "directive," which is defined as "an order or instruction, particularly from a central authority."[61] NERC explains that the "context of the Reliability Standards in which the term 'directive' appears is also

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[57] *Id.* at 30 (quoting Texas RE Decision at 10). *See also* NERC Compliance Committee Decision at 13 (quoting Texas RE language).

[58] Reliability Standard COM-002-2, Requirement R2 provides:

> Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall issue directives in a clear, concise, and definitive manner; shall ensure the recipient of the directive repeats the information back correctly; and shall acknowledge the response as correct or repeat the original statement to resolve any misunderstandings.

[59] NextEra Application at 31 (quoting Compliance Committee Decision at 28).

[60] *Id.* at 31.

[61] NERC Answer at 8 (citing NERC Compliance Committee Decision at 27; and *American Heritage Dictionary of the English Language* (5th ed. 2014)). NERC states that a court interpreting a statute is bound by the "literal or usual meaning of its words" unless this would lead to "absurd results." *Id.*

illustrative."[62] Namely, the purpose of Reliability Standard IRO-001-1 is to ensure that reliability coordinators have the authority to direct entities to take the actions needed to return the system to a reliable state. Similarly, Reliability Standard TOP-001-1 is designed to provide reliability entities with the authority to direct the actions of others. NERC maintains that, applying the definition and context in a straightforward manner to the facts in the case, it is clear that ERCOT issued a directive for purposes of Reliability Standards IRO-001-1 and TOP-001-1.

40. NERC asks that the Commission reject NextEra's *ad hoc* interpretation that would avoid the plain meaning of "directive" and, instead, require an examination of: (1) ERCOT's intent when issuing the instruction; and (2) whether ERCOT complied with other Reliability Standards and documents not explicitly referenced in Reliability Standards IRO-001-1 and TOP-001-1 when communicating the instruction. NERC contends that neither consideration advanced by NextEra is relevant to the determination of whether NextEra violated the subject Reliability Standards. Rather, NERC asserts that, applying the plain meaning of the term directive, Texas RE compliance staff "stated a *prima facie* case through the testimony and evidence presented at the [Texas Commission] hearing that a directive had been issued, thus meeting the burden of persuasion in the proceeding."[63]

41. Trade Associations comment that, while NextEra has accepted full responsibility for failing to respond to the ERCOT dispatch instruction, the Commission must address whether a Regional Entity can make an *ex post* determination on what the operator should have intended in issuing the instruction without developing supporting evidence of the actual intent of the operator. Further, Trade Associations state that the Commission should clarify that a violation of a market rule or protocol does not automatically equate to a reliability violation.

42. NextEra, in its answer to NERC, states that, while a dictionary definition (e.g., plain, ordinary meaning of a term) may be the starting point of the inquiry in interpreting the meaning of the term "directive," the purpose and context in which the term is used must be considered. According to NextEra, NERC does not adequately address the "context" but, rather, simply indicates that an out of merit energy instruction is equivalent to a directive under a Reliability Standard. Thus, NextEra disagrees with NERC's claim that the Texas RE staff met its burden of persuasion and posits that the Texas RE staff should have interviewed the ERCOT operator, which did not happen.

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[62] *Id.* at 8.

[63] *Id.* at 10.

d. Commission Determination

43. The Commission finds that the ERCOT electronic communication issued to NextEra on October 12, 2008 constituted a directive and reliability directive for purposes of Reliability Standards IRO-001-1 Requirement R8 and TOP-001-1 Requirement R3, respectively. At the time of the 2008 incident, neither Texas RE nor NERC had defined directive or reliability directive.[64] Given that circumstance, it was reasonable for Texas RE and NERC to apply the common, dictionary definition of directive as "an order or instruction, particularly from a central authority."[65] We find that the common, dictionary definition aptly describes the ERCOT out of merit energy instruction issued to NextEra that clearly required NextEra to curtail its generator output by a certain time to address a reliability issue - overloading on a transmission line. This is not to say that every dispatch instruction automatically equates to a directive pursuant to Reliability Standards.[66] However, we determine that the specific communication issued by ERCOT to NextEra meets the common understanding of the term directive, or reliability directive, as used in IRO-001-1 and TOP-001-1.

44. Moreover, we agree with NERC and NextEra that the application of the common definition of the term "directive" is not the end of the analysis; and that the context in which the term is used must also be considered.[67] Based on our review of the record and arguments submitted by the parties to the proceeding, we are persuaded that the context in which the term directive is used also supports the conclusion that the ERCOT communication constituted a directive. In particular, we agree with NERC that IRO-001-

[64] NERC Compliance Committee Decision at 11; NextEra Application at 18.

[65] NERC Answer at 8 (citing Compliance Committee Decision at 27; and *American Heritage Dictionary of the English Language* (5th ed. 2014)). *Cf.* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 461 (directing NERC to define the term "sabotage" as used in Reliability Standard CIP-001-1 and determining that, in the interim, the common, dictionary understanding of the term "should suffice in most instances").

[66] Trade Associations ask the Commission to "clarify that a violation of a market rule or protocol does not automatically equate to a reliability violation," indicating that "while not explicit in this case" this proposition seems to be an "undercurrent" in the record. Trade Associations Comments at 9. As indicated in the text above, we limit our determination to specific facts in the immediate proceeding and do not draw any general conclusions about equating market rule violations and non-compliance with Reliability Standards.

[67] *See* NERC Answer at 8; NextEra Answer to Answer at 9-10.

1 is intended to ensure that reliability coordinators have the authority to direct reliability entities to take the actions – including the "re-dispatch of generation" – needed to return the system to a reliable state.[68] In that context, Requirement R8 clearly states that directives are the means for a Reliability Coordinator to exercise this authority.[69] Moreover, the ERCOT out of merit energy instruction, which directed the re-dispatch of generation to address transmission line overloading, corresponds to the language and context of both IRO-001-1 Requirement R8 and TOP-001-1 Requirement R3.[70]

45. Further, we are not persuaded by NextEra's arguments that the Texas RE Board and NERC Compliance Committee erred by failing to consider additional evidence that would provide context as to whether the ERCOT out of merit energy instruction was a "directive" pursuant to the two Reliability Standards. First, we are not persuaded by NextEra's claim that Texas RE and NERC erred by failing to determine the intent of the ERCOT operator at the time he communicated the out of merit energy instruction. Rather, we believe that objective evidence that the reliability coordinator gave a directive based on the content of the communication is adequate – if not preferable - to probing the mind of the operator. As indicated by the NERC Compliance Committee Decision, the reliability coordinator gave a command or instruction to another registered entity to take a clear and specific action to address a reliability matter – in the immediate proceeding, the re-dispatch of generation to resolve a transmission line overloading.[71] While NextEra contends that the operator could have simply intended NextEra to follow the instruction based on ERCOT market rules and good utility practice (and NERC's rationale could result in "overriding" the intent of the ERCOT operator), we question the value and practicality of this approach. Taken to its logical conclusion, this rationale could result in a registered entity questioning a reliability coordinator in real time whether an instruction is a directive, and the source of authority for that directive. Rather, we believe the better approach is that - assuming the reliability coordinator's instruction is clear and unambiguous - the generator operator or other registered entity must follow the instruction unless such action would violate safety, equipment or regulatory or statutory

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[68] *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 889 ("IRO-001-1 requires that a reliability coordinator have . . . the authority to act and direct reliability entities to maintain system operations under normal, contingency and emergency conditions").

[69] NERC Compliance Committee Decision at 12 (quoting Texas RE Board Decision at 8).

[70] *See* NERC Answer at 9-10 and citations to record therein.

[71] NERC Compliance Committee Decision at 19-21.

requirements – as prescribed by IRO-001-1 Requirement R8 and TOP-001-1 Requirement R3. The fact that there may be dual authorities for issuing the instruction should not open up an inquiry as to whether the reliability coordinator intended to issue the directive under one authority and not the other.[72]

46. Moreover, we are not persuaded by NextEra's argument that, if ERCOT intended the instruction issued pursuant to ERCOT market rules to constitute a directive or reliability directive, ERCOT should have issued the out of merit energy instruction pursuant to Reliability Standard COM-002-2, which requires three-part communication. While NERC and Texas RE contend that neither IRO-001-1 nor TOP-001-1 require the that directives be issued in a particular manner, NextEra argues that COM-002-2 requires three-part communication in issuing all directives under any of the 22 Reliability Standards that include the word "directive" (but do not explicitly reference COM-002-2). On this matter, the NERC Compliance Committee concluded that a preponderance of the evidence supports the conclusion that the ERCOT instruction was a directive regardless of whether three-part communication was required by ERCOT and NextEra, explaining:

> Reliability Standard COM-002-2 R2 does not define "directive," but does provide the protocols to use when issuing directives. Specifically, R2 requires entities to use three-part communication. Three-part communication as listed in R2 cannot be accomplished with written directives. Therefore, COM-02-2 R2 implicitly applies to the use of three-part communication in verbal exchanges. The justification for three-part communications in verbal exchanges is to ensure the message is accurately conveyed and understood. When communicating in writing, the possibility of misunderstanding between the parties is lessened. . . .[73]

We agree with NERC's rationale and conclude that the application of three-part communication is not determinative whether the electronically communicated directive was issued under the TOP and IRO standards.

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[72] Because of our conclusion, we find it unnecessary to analyze NextEra's claim that, because ERCOT did not identify possible Reliability Standard violations in the 2008 Incident Report, "ERCOT's silence creates ambiguity as to its intent." NextEra Application at 19. Nor do we view this as evidence of Texas RE staff's "flawed" investigation. In particular, we do not believe that a lack of identification of a possible violation of a reliability standard by ERCOT precluded Texas RE or NERC from making an independent determination that such a violation occurred.

[73] NERC Compliance Committee Decision at 27-28.

47. We are also not persuaded by NextEra's argument that ERCOT Power Operations Bulletin No. 388 makes clear that an out of merit energy instruction is not a directive. Fundamentally, the bulletin revises the ERCOT Transmission and Security Desk Procedure Manual and appears to address directives issued pursuant to ERCOT protocols. The bulletin does not specifically mention Reliability Standards or directives that fall within the scope of Reliability Standards. Moreover, while NextEra is correct that the bulletin repeatedly states that "all directives" shall be in a clear, concise, and definitive manner" using three-part communication, this language never appears in the bulletin as a general statement but, rather appears in specific scenarios, following a specific verbal script. For example, as to the verbal issuance of an emergency notice, the bulletin states:

> Typical script: "This is ERCOT operator [first and last name]. ERCOT is issuing an Emergency Notice for [state Emergency Notice]. [TO] please repeat this directive back to me. That is correct, thank you."
>
> All directives shall be in a clear, concise and definitive manner. Ensure the recipient of the directive repeats the information back correctly. Acknowledge the response as correct or repeat the original statement to resolve any misunderstandings.[74]

The bulletin mentions out of merit energy instructions in only two provisions. First, section 2.2.3, step 9, provides that, if an out of merit energy instruction becomes necessary, certain generator units that cannot respond to market deployments may be deployed to zero output, which would be considered a local technique (referenced in step 8).[75] Second, section 2.2.12, which prescribes actions for the overload of a specific autotransformer, identifies one option as issuing an out of merit energy VDI (verbal dispatch instruction) to a specific generator to relieve the overload.[76] In light of the

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[74] Bulletin, section 2.5.4 (Issue and Emergency Notice), step 3. Other provisions have a similar "script" followed by the "all directives" language. *E.g.*, Bulletin, section 2.2.6 (Pre-Contingency Action Plans), step 3; section 2.5.2 (Issue an Advisory), step 3; section 2.5.6 (Implement EECP), step 1b.

[75] *See* Bulletin, section 2.2.3 (Zonal Congestion Management), step 9.

[76] *Id.*, section 2.2.12 (Post-Contingency Overload of the Sandow Autotransformer), step 1. This provision does not include a script or state that "all directives" must use three-part communication. Steps for issuing Verbal Dispatch Instructions are set forth in section 2.6.1 of the bulletin. While requiring three-part communication for such instructions, the bulletin revised section 2.6.1 to apply only to transmission owners and not generators.

above, we disagree with NextEra that the bulletin supports the general proposition that all ERCOT operator directives must be issued verbally using three-part communication. Rather, while definitive that in certain circumstances when verbal communications are used they must be in three-part communication, the bulletin is ambiguous regarding the expectation regarding out of merit energy instructions – both with regard to the acceptable use of electronic communication to issue a directive and the necessary use of three-part communication.[77]

48. We also find unpersuasive NextEra's arguments related to the July 2009 NERC management memorandum (not presented to the NERC Board of Trustees for approval) regarding three-part communications.[78] We fail to see how this document sheds any light on the incident at issue in this proceeding that occurred nine months earlier.[79]

49. In sum, we find that the ERCOT electronic communication issued to NextEra on October 12, 2008 constituted a directive and reliability directive for purposes of Reliability Standards IRO-001-1 Requirement R8 and TOP-001-1 Requirement R3, respectively. The ERCOT communication is consistent with the plain, dictionary meaning of the term "directive." Other evidence regarding the context and purpose of the communication supports the determination that the ERCOT communication was a directive for the purposes of these requirements.

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[77] *See* NERC Compliance Committee Decision at 24 ("references to the issuance of directives in ERCOT Bulletin #388 appear to be addressing verbal communications and do not expressly require the use of three-part communications for electronic instructions").

[78] *See id*. at 26-27.

[79] Based on its position regarding the communication of directives, NextEra also asserts that it did not have actual or "constructive knowledge" that its inaction violated a Reliability Standard. NextEra Application at 41-48. However, NextEra understood or should have understood that it had received an instruction to take clear and specific action in response to ERCOT order, but did not do so. In this circumstance, we are not persuaded that NextEra should be exonerated from monetary penalties based on an alleged lack of constructive knowledge. In Order No. 693, the Commission found that "if a dispute arises over compliance and there is a legitimate ambiguity regarding a particular fact or circumstance, that ambiguity can be taken into account in the exercise of the Commission's enforcement discretion." Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 275.

2. Applicability of Reliability Standard TOP-001-1 Requirement R3 in Non-Emergency Conditions

a. NERC Compliance Committee Decision

50. The NERC Compliance Committee, affirming the Texas RE Board, concluded that Reliability Standard TOP-001-1 Requirement R3 is not limited to emergency conditions. While acknowledging that the purpose of Reliability Standard TOP-001-1 is "[t]o ensure reliability entities have clear decision-making authority . . . to return the transmission system to normal conditions during an emergency," the Compliance Committee maintained that "the purpose statement of a Reliability Standard is a general guideline and not an enforceable Requirement."[80] The Compliance Committee explained that TOP-001-1 has eight Requirements, of which only Requirements R1 and R5 have language limiting the Requirements to emergencies, while other Requirements are silent. Noting that principles of statutory construction and contract interpretation (1) favor interpretations that give meaning to all of the words of a statute and (2) indicate that the presence of limiting language in one part of a statute that is omitted in another part is intentional, the NERC Compliance Committee reasoned, "[i]f the purpose statement of TOP-001-1 is interpreted as descriptive rather than limiting, it gives effect to the language contained in both R1 and R5 and does not contradict the language throughout the [Reliability] Standard."[81] Elsewhere in the Decision, the NERC Compliance Committee recited the Texas RE Board rationale that certain Requirements of Reliability Standard TOP-001-1 apply in non-emergency situations, such as the Requirement R5, which requires the transmission operator to notify the reliability coordinator of "anticipated emergencies."[82]

b. NextEra Application

51. NextEra argues that the NERC Compliance Committee erred in finding that the issuance of reliability directives pursuant to Reliability Standard TOP-001-1 Requirement R3 is not limited to emergencies. NextEra asserts "that the 'emergency' condition in the purpose section elicits the intent of the requirements and thus limits the applicability of the Standard's requirements to emergencies" and notes that the Texas Commission

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[80] Compliance Committee Decision at 36 (citing Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 253).

[81] NERC Compliance Committee Decision at 36.

[82] *Id.* at 13.

agreed with this rationale in concluding that NextEra did not violate Reliability Standard TOP-001-1.[83]

52. NextEra contends that NERC's explanation - that the purpose statement is descriptive and not limiting - is inconsistent with NERC's interpretation of Reliability Standard COM-002-2, would result in compliance gaps, and would make the purpose section in Reliability Standards superfluous. NextEra also takes issue with the Compliance Committee's reliance on statutory interpretation, arguing that "nothing in section 215 [of the FPA] equates a Reliability Standard developed by the ERO to a Congressional statute."[84]

53. NextEra argues that separating the requirements from the purpose section of a Reliability Standard is inconsistent with NERC's past practice and could result in future uncertainty on the meaning of standards. Noting that the phrase "real-time emergencies" appears in the purpose statement and Requirement R1 of Reliability Standard COM-002-2 but not Requirement R2, NextEra asserts that a consistent approach would result in Requirement R2 applying in both normal and real-time emergencies. According to NextEra, this would undermine a NERC Board-approved interpretation that relies on the purpose statement to support that three-part communication is only required during real-time emergencies.[85] NextEra argues that the NERC Compliance Committee's approach to applying rules of statutory interpretation would create other problems in the enforcement of other Reliability Standards such as TOP-001-1 and PRC-005-2. NextEra claims that the NERC Compliance Committee's position that the purpose section of a standard is guidance is at odds with Commission Order No. 753, where the Commission was called upon to review an interpretation of Reliability Standard TOP-001-1 Requirement R8, and concluded that "[t]he interpretation supports the stated purpose of the Reliability Standard."[86]

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[83] NextEra Application at 32.

[84] *Id*. at 33.

[85] *Id*. at 34. NextEra notes that the Commission has not approved the Reliability Standard COM-002-2 interpretation. *Id.* at 29.

[86] NextEra Application at 35 n.93 (citing *Electric Reliability Organization Interpretation of Transmission Operations Reliability Standard*, Order No. 753, 136 FERC ¶ 61,176, at P 14 (2011)).

c. NERC Answer and Trade Associations Comments

54. NERC maintains that compliance is to be measured only by whether the entity met or failed to meet the terms in a specific, self-contained Reliability Standard.[87] NERC contends that the purpose statement of a standard, like Measures and Levels of Non-Compliance, serve as general guidelines and not an enforceable requirement. NERC asserts that the NERC Compliance Committee's application of principles of statutory construction and contract interpretation is sound; and the purpose statement of Reliability Standard TOP-001-1 should be interpreted as descriptive to give effect to all of the language of the Requirements of the standard while avoiding internal contradictions.

55. Trade Associations support NextEra, arguing that the Commission should evaluate how the NERC Compliance Committee should use the purpose statement in a Reliability Standard, especially where the purpose statement contains a limit to the applicability of the standard that is not explicitly stated in the Requirements. Trade Associations express concern that the Compliance Committee's approach will effectively read out purpose statements altogether. According to Trade Associations, adoption of the Compliance Committee's argument would mean that registered entities would have to go requirement-by-requirement to determine if the scope of the requirement differs from its stated purpose because a limiting (or expansive) word is missing.

d. Commission Determination

56. We affirm NERC's conclusion that Reliability Standard TOP-001-1 Requirement R3 is not limited to emergency conditions. Moreover, we agree with NERC that the purpose statement of a Reliability Standard does not control the applicability of the standard. This understanding is consistent with the Commission's statement in Order No. 693 that "the most critical element of a Reliability Standard is the Requirements" as the "the Requirements within a standard define what an entity must do to be compliant. . . ."[88] While other language of a Reliability Standard may assist in interpreting a requirement where an ambiguity exists, the purpose statement of a Reliability Standard alone does not control the scope or applicability of a Reliability Statement even though the purpose statement of a Reliability Standard may provide useful context for interpreting the Requirements.[89] Moreover, a reasonable reading of the

[87] NERC Answer at 12.

[88] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 253.

[89] *Id.* at PP 253, 280 (discussing relevance of compliance information set forth in a Reliability Standard).

purpose statement would be as a declaration of minimum qualifications for reliability entities, i.e., to ensure reliability entities "have clear decision-making authority and capabilities" that would allow them "to take appropriate actions or direct the actions of others to return the transmission system to normal conditions during an emergency," and not a limit on the use of that authority or capabilities to only emergency situations. Further, we agree with the NERC Compliance Committee that the language and context of the Requirements of Reliability Standard TOP-001-1 make it reasonably clear that some provisions, including Requirement R3, apply in non-emergency conditions– particularly here, where ERCOT issued the out of merit energy instruction to avert a potential emergency. We note that, while some requirements of Reliability Standard TOP-001-1 explicitly apply during emergency conditions, other requirements (including Requirement R3 at issue here) do not include an explicit limitation to emergency conditions.[90] While the clarity of the language of the Reliability Standard TOP-001-1 may not be optimal because of the wording of the purpose statement, on balance, we find that it was reasonable for the NERC Compliance Committee to conclude that Reliability Standard TOP-001-1 Requirement R3 applies to non-emergency conditions in addition to emergency conditions.

57. In response to Trade Associations, our determination does not render the purpose statement of a Reliability Standard meaningless, as it can provide context and guidance when interpreting an otherwise potentially ambiguous requirement of a standard. However, as discussed above, and consistent with Order No. 693, the requirements of a Reliability Standard set forth the enforceable obligation with which applicable entities must apply. Further, we are not persuaded by NextEra's characterization that the BOTCC Decision undermines prior NERC Board of Trustees actions. Rather, the BOTCC Decision is consistent with the Commission's explanation that the purpose statement of a Reliability Standard may provide useful context for interpreting the Requirements. In addition, we are not persuaded by NextEra's argument that Order No. 753 supports NextEra's position. In that order, while the Commission stated that NERC's interpretation supported the purpose of the Reliability Standard, the Commission concluded that the NERC interpretation was "consistent with the language *of the requirement*."[91] It is on that basis – not the purpose statement – that the Commission

[90] As observed by the Texas RE Board, one provision explicitly requires action in anticipation of emergency conditions. *See* NERC Compliance Committee Decision at 36 (quoting Texas RE Board Decision at 22); s*ee also* Reliability Standard TOP-001-1 Requirement R5 (requiring that "Transmission Operators shall inform its Reliability Coordinator . . . of real time *or anticipated emergency conditions*, and take actions to avoid, when possible, or mitigate the emergency") (emphasis added).

[91] Order No. 753, 136 FERC ¶ 61,176 at P 14 (emphasis added).

approved the interpretation. Moreover, the interpretation addressed the division of registered entity responsibilities under a specific Requirement, R8, which explicitly applies to system emergencies; the interpretation does not address the broader question of whether the standard as a whole applies to non-emergency situations. Finally, we believe in any event that the Compliance Committee's decision supports the TOP-001-1 purpose statement because an entity's failure to respond to directives to prevent emergency situations reasonably is related to that entity's capability to take appropriate actions, as directed, during an emergency.

3. NERC Procedure, Process, and Standard of Review of the Texas RE Board Decision

58. NextEra and Trade Associations raise several concerns regarding the procedural due process during the proceedings leading to this proceeding before the Commission. Below, we address the following claims of procedural error: (1) application by the NERC Compliance Committee of an arbitrary and capricious standard of review to the Texas RE Board decision; (2) acceptance of parol evidence; and (3) failure to ensure consistency among regions in interpreting a Reliability Standard.

a. Application of Arbitrary and Capricious Standard of Review

i. NextEra Application

59. NextEra claims that the NERC Compliance Committee erroneously applied an "arbitrary and capricious" standard of review. NextEra argues that neither NERC nor Texas RE is part of the judicial system and thus it is unclear why an arbitrary and capricious standard is appropriate. In addition, NextEra argues that the arbitrary and capricious standard of review conflicts with the *de novo* standard of review that the Commission previously found should be employed by NERC.[92]

ii. NERC Answer and Trade Associations Comments

60. NERC answers that the NERC Compliance Committee applied a proper standard of review when affirming the Texas RE Board Decision. NERC explains that the review is based upon specific information set forth in section 409 of the NERC Rules of Procedure, which pertains to appeals of final decisions from Regional Entity hearing

[92] NextEra Application at 48-49 (quoting ERO Certification Order, 116 FERC ¶ 61,026 at P 491).

bodies.[93] NERC notes that the Commission, in approving section 409, found that "NERC's procedures afford appropriate deference to the Regional Entities' role as reliability managers and their familiarity with operating conditions by prohibiting consideration on appeal of any fact that is not in the record compiled by the Regional Entity."[94] While NERC acknowledges that the Commission also stated that the ERO "should have *de novo* review authority on appeal in matters where consistency is desirable, such as the interpretation of standards, . . . or when determining whether the factual record supports a particular penalty or remedial action,"[95] NERC contends that the immediate proceeding pertains to the particular facts and circumstances surrounding the NextEra incident and does not have such broad implications.

61. Trade Associations assert that the Commission should not accept the wrongful use of an arbitrary and capricious standard of review. Rather, according to Trade Associations, the Commission should find that NERC has the "authority and responsibility" to conduct a *de novo* review as set forth in the ERO Certification Order.

iii. Commission Determination

62. While the NERC Compliance Committee Decision certainly could have been clearer on the matter, we find that the Decision does not adopt an "arbitrary and capricious" standard of review as claimed by NextEra. In an upfront summary of its findings, the NERC Compliance Committee Decision states that "after engaging in a reasoned analysis of the arguments and evidence before it, the [NERC Compliance Committee] affirms the Decision of the Texas Board."[96]

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[93] NERC Rules of Procedure, section 409.5 (Decision), provides:

> The Compliance Committee of the NERC Board of Trustees shall decide the appeal, in writing, based upon the notice of appeal, the record of the proceeding before the Regional Entity Hearing Body, the responses, and any reply filed with NERC. At its discretion, the Compliance Committee may invite representatives of the entity making the appeal and the other Participants in the proceeding . . . to appear before the Committee.

[94] NERC Answer at 16 (citing, ERO Certification Order, 116 FERC ¶ 61,062 at P 491).

[95] *Id.*

[96] NERC Compliance Committee Decision at 10.

63. While the NERC Compliance Committee Decision references the "arbitrary and capricious" standard in three specific instances, we disagree with NextEra that the Decision adopted this standard of review. Rather, it is clear that, in each instance, the Decision simply responded to NextEra's arguments raised before the NERC Compliance Committee that the Texas RE Board "acted arbitrarily and capriciously."[97] In each instance, the NERC Compliance Committee provides a caveat that it "does not address here the appropriateness of applying the 'arbitrary and capricious' standard to the decisions of the Texas RE Board" and then proceeds to find that "nevertheless" the Texas RE Board did not act arbitrarily and capriciously.[98] Moreover, in each instance, the NERC Compliance Committee also engaged in a review of the evidence before reaching its conclusions that we substantively uphold in our review as discussed above.

64. Going forward, NERC has the responsibility to articulate the legal standard of review that NERC applies in reviewing the determination of a Regional Entity hearing body. Regardless of what the NERC Compliance Committee standard of review was, based on our own independent review of the record, we find that Texas RE acted properly in finding violations of the Reliability Standards.

b. Parol Evidence

i. NERC Compliance Committee Decision

65. In response to NextEra's claim that the Texas RE Board relied on parol evidence and other documents that were not part of the record, the NERC Compliance Committee found that "the Texas RE was entitled to take official notice of information available outside of the record of the proceeding during oral arguments regarding the development of the TOP Reliability Standards. Moreover, the NERC Compliance Committee finds that Texas RE based its decision on the language of the TOP Reliability Standard and Requirement at issue, Reliability Standard TOP-001-1 Requirement R3."[99]

66. The NERC Compliance Committee explained that, while the Texas RE Board was hearing oral arguments, in response to a question of a Texas RE Board member, another Board member provided information regarding the development of the TOP Reliability Standards and sketched a diagram that was accepted into evidence without objection.

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[97] *See id.* at 18-19, 28-29, 31-32; *compare*, Notice of Penalty, Exh B-15 (NextEra appeal to NERC) at 3-4.

[98] *See, e.g.*, NERC Compliance Committee Decision at 19.

[99] NERC Compliance Committee Decision at 17.

The NERC Compliance Committee concluded that this exchange did not create reversible error, explaining that the Texas RE Board based its decision on the language of TOP-001-1. In addition, the Compliance Committee Decision noted that, while neither the Texas RE nor NERC Rules of Procedure specifically address the taking official notice of information outside of the record, the NERC Rules do exempt hearing proceedings from the generally recognized rules of evidence.[100]

ii. NextEra Application

67. NextEra contends that Texas RE and the NERC Compliance Committee went beyond the record evidence and developed separate theories that were not part of the underlying proceeding and go beyond the four corners of the Reliability Standard itself. NextEra claims that, in finding that Reliability Standard TOP-001-1 Requirement R3 is applicable, both the Texas RE Board and NERC Compliance Committee impermissibly rely, in part, on information introduced by a Texas RE Board member. According to NextEra, the information provided on the "history" of Reliability Standard TOP-001-1 is "immaterial to the enforcement of Standards" under FPA section 215 and, therefore, the Commission should reject the expansion of the record based on parol evidence.[101]

iii. NERC Answer and Trade Associations Comments

68. NERC reiterates that the NERC Compliance Committee and the Texas RE Board did not rely on the "historical" evidence at issue but, rather, they based their decisions on the language of Reliability Standard TOP-001-1 Requirement R3.[102]

69. Trade Associations comment that use of parol evidence is unacceptable and unnecessary since the purpose statement of Reliability Standard TOP-001-1 does not contain an ambiguity that would lead to the use of secondary sources.

iv. Commission Determination

70. We are not persuaded by NextEra and Trade Associations that the Texas RE Board or NERC Compliance Committee erred by accepting parol evidence into the record. Procedurally, NextEra does not cite to any source that parol evidence must be

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[100] *Id.* (citing NERC Rules of Procedure, App. 4C (Compliance Monitoring and Enforcement Program), Att. 2 (Hearing Procedure), section 1.6.11(b).

[101] NextEra Application at 37.

[102] NERC Answer at 13 n.36.

excluded. To the contrary, the hearing procedures set forth in the NERC Rules of Procedure explicitly provide that "[t]he admission of evidence shall not be limited by the generally recognized rules of evidence as applied in the courts of the United States . . ."[103] Substantively, NextEra has not adequately demonstrated that the admission of the parol evidence was beyond "harmless error," as the written Decisions do not rely on the parol evidence and, based on our review, it appears that the material at issue was simply "supporting," background information. Accordingly, we deny NextEra's request on this issue.

c. Regional Consistency

i. NextEra Application

71. NextEra states that NERC, in its oversight role, is obligated to ensure consistency among regions to which it delegated duties and functions. NextEra claims that it is not aware of any Regional Entity besides Texas RE that has found a violation of Reliability Standards IRO-001-1 Requirement R8 or TOP-001-1 Requirement R3 for failing to follow a written dispatch instruction. NextEra asserts that "Independent System Operators (ISOs) in other regions have adopted similar rules to ERCOT for the communication of directives, and we would be surprised if they have not been audited by their respective Regional Entities."[104] NextEra contends that NERC retains broad authority regarding matters of national consistency, and its failure to exercise that authority in the proceeding constituted error.

ii. NERC Answer and Trade Associations Comments

72. NERC answers that it and the Regional Entities are committed to ensuring and promoting consistency across the ERO enterprise. NERC contends, however, that the immediate proceeding pertains to the specific facts and circumstances whether NextEra complied with the provisions of specific Reliability Standards, and the NERC Compliance Committee properly considered the facts and circumstances presented to it in accordance with the NERC Rules of Procedure.

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[103] NERC Rules of Procedure, App. 4C, Att. 2 (Hearing Procedure), section 1.6.11(b), (stating "[t]he admission of evidence shall not be limited by the generally recognized rules of evidence as applied in the courts of the United States"). *Cf.*, *BP America Inc.*, 147 FERC ¶ 61,130 at P 21 n.46 (2014) (stating that the Commission is not strictly bound by the Federal Rules of Civil Procedure, although they may serve as a "guideline").

[104] NextEra Application at 39.

73. Trade Associations argue that confidence in the NERC compliance monitoring and enforcement program is based upon the consistent implementation of that program.

iii. Commission Determination

74. We agree that NERC, as the ERO, is responsible to ensure consistent compliance outcomes and consistent interpretation of the Reliability Standards. While we understand the potential difficulty of "proving a negative," i.e., that other Regional Entities treat out of merit energy instructions differently than Texas RE, NextEra has not provided any information beyond speculation that would suggest that the proceeding raises issues of inconsistency among regions. In this circumstance, we are not persuaded that NERC erred in declining to delve further into matter. Accordingly, we reject NextEra's request regarding this issue.

VI. Conclusion

75. We affirm the findings of the NERC Compliance Committee Decision that NextEra violated Reliability Standards IRO-001-1 Requirement R8 and TOP-001-1 Requirement R3 by failing to timely comply with a reliability directive. Further, we are not persuaded by other substantive and procedural arguments against NERC's determination provided by NextEra or other parties, for the reasons discussed above. Accordingly, we affirm the $52,000 penalty assessed against NextEra.

The Commission orders:

The Notice of Penalty against NextEra, including the assessment of a $52,000 penalty amount, is hereby affirmed, as discussed in the body of this order.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation — Docket No. RR15-2-000

NOTICE OF EXTENSION OF TIME

(March 16, 2015)

On March 13, 2015, the North American Electric Reliability Corporation (NERC) filed a request for a 45-day extension of time, until July 6, 2015, to submit its Rules of Procedure changes in accordance with the Commission's February 19, 2015 Order,[1] in the above referenced proceeding. NERC states that the additional time is necessary to accommodate each of the required steps within the open, collaborative, and participatory process that applies to developing revisions of the NERC Rules of Procedure.

Upon consideration, notice is hereby given that NERC is granted the requested extension of time, to and including July 6, 2015, to submit its Rules of Procedure revisions to comply with the Commission's February 19, 2015 Order, in the above-referenced proceeding.

Kimberly D. Bose,
Secretary.

[1] *North American Electric Reliability Corporation*, Order on Electric Reliability Organization Reliability Assurance Initiative and Requiring Compliance Filing, 150 FERC ¶ 61,108 (2015) (February 19 Order).

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150 FERC ¶ 61,109
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM14-12-000; Order No. 804]

Demand and Energy Data Reliability Standard

(Issued February 19, 2015)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Commission approves Demand and Energy Data Reliability Standard MOD-031-1 developed by the North American Electric Reliability Corporation (NERC), which the Commission has certified as the Electric Reliability Organization responsible for developing and enforcing mandatory Reliability Standards. In addition, the Commission directs NERC to develop a clarifying modification to the Reliability Standard.

EFFECTIVE DATE: This rule will become effective **[Insert date 60 days after publication in the FEDERAL REGISTER]**.

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SUPPLEMENTARY INFORMATION:

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150 FERC ¶ 61,109
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Cheryl A. LaFleur, Chairman;
Philip D. Moeller, Tony Clark,
Norman C. Bay, and Colette D. Honorable.

Demand and Energy Data Reliability Standard Docket No. RM14-12-000

ORDER NO. 804

FINAL RULE

(Issued February 19, 2015)

1. Pursuant to section 215(d) of the Federal Power Act (FPA),[1] the Commission approves Reliability Standard MOD-031-1 (Demand and Energy Data) developed by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO). Reliability Standard MOD-031-1 provides authority for planners and operators to collect demand, energy and related data to support reliability studies and assessments. In addition, the Commission approves NERC's proposed definitions for the terms Demand Side Management and Total Internal Demand. The Commission also approves the associated implementation plan, violation risk factors and violation severity levels, and NERC's proposed retirement of the currently-effective

[1] 16 U.S.C. 824o(d) (2012).

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Reliability Standards MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1, and MOD-021-1 (Existing MOD C Standards).

2. Further, pursuant to section 215(d)(5) of the FPA, the Commission directs NERC to (1) develop a modification to Reliability Standard MOD-031-1 to clarify certain obligations to provide data to the Regional Entity and (2) consider the compliance obligations of an applicable entity upon receipt of a data request that seeks confidential information.

I. Background

3. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval. Once approved, the Reliability Standards are enforced by the ERO, subject to Commission oversight, or by the Commission independently. In 2006, NERC submitted the initial version of Reliability Standards MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1, MOD-020-0, and MOD-021-1. The Existing MOD C Standards were designed to help ensure that historical and forecasted demand and energy data are available for past event validation and future system assessment. In particular, the Existing MOD C Standards, along with Reliability Standard MOD-020-0, require the collection of actual and forecast demand data necessary to analyze the resource needs to serve peak demand while maintaining a sufficient margin to address operating events. In Order No. 693, the Commission approved the Existing MOD C Standards and Reliability

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Standard MOD-020-0.[2] In addition, the Commission directed NERC to develop certain modifications to the standards.

II. NERC Petition and NOPR

4. In its petition, NERC stated that Reliability Standard MOD-031-1 will provide planners and operators access to actual and forecast demand and energy data, as well as other related information, needed to perform resource adequacy studies.[3] NERC explained that the proposed Reliability Standard also supports the continued development of the reliability assessments prepared by NERC. NERC stated that the proposed Reliability Standard improves the Existing MOD C Standards by: (1) streamlining them to clarify data collection requirements; (2) including transmission planners as applicable entities that must report demand and energy data; (3) requiring applicable entities to report weather normalized annual peak hour actual demand data from the previous year to allow for meaningful comparison with forecasted values; and (4) requiring applicable entities to provide an explanation of how their forecasts compare to actual prior year data.[4]

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[2] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, at PP 1223, 1235, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[3] NERC Petition at 3. The proposed MOD Reliability Standard is not attached to the Final Rule. The complete text of the Reliability Standard is available on the Commission's eLibrary document retrieval system in Docket No. RM14-12 and is posted on the ERO's web site, *available at*: http://www.nerc.com.

[4] NERC Petition at 4.

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5. Reliability Standard MOD-031-1 contains four requirements. Requirement R1 provides that each planning coordinator or balancing authority that identifies a need for the collection of demand and energy data must develop and issue a data request for such data to the relevant entities in its area. The requirement mandates that the data request identify: (i) the entities responsible for providing the data; (ii) the data to be provided by each entity; and (iii) the schedule for providing the data. Requirement R2 obligates the entities identified in a Requirement R1 data request to provide the requested data to their planning coordinator or balancing authority. Requirement R3 requires that the planning coordinator or the balancing authority provide the data collected under Requirement R2 to their Regional Entity, if requested, to facilitate NERC's development of reliability assessments. Requirement R4 requires entities to share their demand and energy data with any applicable entity that demonstrates a reliability need for such data.[5]

6. On September 18, 2014, the Commission issued a Notice of Proposed Rulemaking (NOPR) proposing to approve Reliability Standard MOD-031-1 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. The Commission also requested comments on the collection of demand and energy data. Specifically, the Commission sought comments on: (1) the Commission's understanding that while a planning coordinator or balancing authority may collect demand and energy forecast data under a tariff or other arrangement, the planning coordinator or balancing authority

[5] *Id.* at 5.

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always retains the option to seek the necessary data through a Requirement R1 data request if, for example, the data are not forthcoming through other means; and (2) whether a planning coordinator or balancing authority that receives data through alternative mechanisms remains obligated to provide such data (i.e., within the scope of Requirement R1) to a Regional Entity upon request, as set forth in Requirement R3.

Comments

7. Comments on the NOPR were submitted by NERC, Edison Electric Institute (EEI), ISO New England, Inc. (ISO New England), International Transmission Company d/b/a ITC*Transmission*, Michigan Electric Transmission Company, LLC, ITC Midwest LLC, and ITC Great Plains, LLC (collectively, "ITC Companies"), PacifiCorp, and Idaho Power Company (Idaho Power).

8. NERC, EEI, ISO New England support the Commission's proposed approval of MOD-031-1, and ITC Companies "does not object" to the standard. NERC and other commenters provide responses to the Commission's questions regarding the collection of demand and energy data, as discussed below.

9. NERC, EEI, Idaho Power, and ISO New England confirm the Commission's understanding that the planning coordinator or balancing authority retains the option to seek the necessary data through a Requirement R1 data request. NERC states that the Reliability Standard provides planning coordinators and balancing authorities the authority to issue data requests to compel applicable entities to provide the demand and energy data necessary to conduct reliability assessments. According to NERC, the Reliability Standard does not require planning coordinators and balancing authorities to

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issue such data requests if they have alternative means of obtaining or developing that data but planning coordinators and balancing authorities may always use the authority provided by the Reliability Standard as a backstop to ensure they obtain complete and accurate data.

10. With respect to the issue of whether a planning coordinator or balancing authority that receives data through alternative mechanisms remains obligated to provide such data to a Regional Entity upon request, NERC states that the intent of Requirement R3 was to require all planning coordinators and balancing authorities to provide the necessary demand and energy data to their respective Regional Entities to support the ERO development of seasonal and long-term reliability assessments. NERC commits to modifying the language of Requirement R3 in its standard development process to clarify that planning coordinators and balancing authorities must provide their demand and energy data to their Regional Entity, upon request, whether that data is collected pursuant to the proposed Reliability Standard or through alternative arrangements.

11. With regard to the Commission's question about the obligations of a planning coordinator or balancing authority to share data gathered or obtained through alternative mechanisms, EEI comments that there is no obligation to require a planning coordinator or balancing authority to share such data in a similar manner as required by Requirement R3. EEI adds that it is not aware of any reason that might motivate independent system operators (ISOs) or regional transmission organizations (RTOs) (in their role as planning coordinators or balancing authorities) to withhold such information from the Regional Entity. PacifiCorp agrees with EEI on this issue and favors a finding that Requirement

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R3 should not apply if the planning coordinator or balancing authority receives data through alternative means.

12. In contrast, Idaho Power and ISO New England assert that a planning coordinator or balancing authority that receives data within the scope of Requirement R1 through alternative mechanisms (as opposed to a data request) remains obligated to provide the data to a Regional Entity upon request pursuant to Requirement R3.

13. EEI also requests that the Commission clarify potential conflicts between a transmission provider's obligation to provide data under Reliability Standard MOD-031-1 and its confidentiality obligations under the Open Access Transmission Tariff (OATT) or other confidentiality or nondisclosure restrictions. ITC Companies raises a concern with the inclusion of transmission planners as entities from whom the types of data specified may be requested because, according to ITC Companies, many transmission planners have delegated the collection of data to the ISO or RTO in which they are located.

III. Discussion

14. Pursuant to section 215(d)(2) of the FPA, the Commission approves Reliability Standard MOD-031-1 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. We also approve the new and modified glossary definitions, implementation plan, associated violation risk factors and violation severity levels as well as the retirement of the Existing MOD C Standards. Reliability Standard MOD-031-1 should continue to provide planners and operators access to complete and accurate demand and energy data to allow such entities to conduct their own resource adequacy

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analyses to serve peak demand. As noted above, NERC, EEI, and ISO New England support approval of MOD-031-1, and no commenters oppose approval. ITC Companies "does not object" to the standard and "concurs with the Commission that MOD-031-1 will meaningfully enhance the ability of transmission planners and operators to conduct resource adequacy analyses and plan for peak load conditions."[6]

15. We also find that the Reliability Standard should provide for consistent documentation and information sharing practices for demand and energy data, and promotes efficient planning practices across the industry and supports the identification of needed system reinforcements. Further, the Commission finds that Reliability Standard MOD-031-1 improves the Existing MOD C Standards by providing applicable entities the authority to collect demand and energy data, and related information, to support reliability assessments and also includes transmission planners as applicable entities that must report demand and energy data.

16. Further, as discussed below, we direct NERC to (1) develop a modification to Reliability Standard MOD-031-1 to clarify certain obligations to provide data to the Regional Entity and (2) consider the compliance obligations of an applicable entity upon receipt of a data request that seeks confidential information.

[6] ITC Comments at 2.

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A. Demand and Energy Data Issues Raised in the NOPR

17. As discussed above, the Commission sought comment in the NOPR on several questions in connection with the collection of demand and energy data. With regard to the responsive comments on the NOPR question regarding the collection of data through mechanisms other than data requests, the Commission accepts the explanation provided by NERC and other commenters that, while a planning coordinator or balancing authority may collect demand and energy forecast data under a tariff or other arrangement, the planning coordinator or balancing authority always retains the option to seek the necessary data through a Requirement R1 data request if, for example, the data are not forthcoming through other means.

18. Further, the Commission raised a concern in the NOPR regarding whether a planning coordinator or balancing authority that receives data "through alternative mechanisms" remains obligated to provide such data (i.e., within the scope of Requirement R1) to a Regional Entity upon request, as set forth in Requirement R3. We accept NERC's explanation that the "intent of Requirement R3 was to require all planning coordinators and balancing authorities to provide the necessary demand and energy data to their respective Regional Entities to support the [ERO]'s development of seasonal and long-term reliability assessments," although "a strict reading" of Requirement R3 "indicates that it applies only to data collected pursuant to a data request

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issued under this Reliability Standard."[7] NERC has the statutory responsibility to conduct periodic assessments of the reliability and adequacy of the Bulk-Power System, and we believe that it is incumbent on users, owners and operators subject to compliance with section 215 of the FPA to provide the necessary data to support such assessments.[8] Accordingly, pursuant to section 215(d)(5) of the FPA and consistent with NERC's comments,[9] we direct NERC to develop a modification to MOD-031-1 through the standards development process to clarify that planning coordinators and balancing authorities must provide demand and energy data upon request of a Regional Entity, as necessary to support NERC's development of seasonal and long-term reliability assessments.

B. Other Issues

19. EEI seeks Commission clarification of a "potential conflict" between a transmission provider's obligation to provide data under MOD-031-1 and the transmission provider's confidentiality obligations under an OATT or other confidentiality restrictions.[10] Under MOD-031-1, Requirement R2, an applicable entity must provide data requested by its planning coordinator or balancing authority in

[7] NERC Comments at 2-3. *See also* EEI Comments at 3.

[8] 16 U.S.C. 824o(g).

[9] *See* NERC Comments at 3.

[10] *See* EEI Comments at 3-4 (citing Article 22.1.10 of the *pro forma* large generation interconnection agreement).

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accordance with the Requirement R1 data request provision. EEI notes that, under Requirement R4, an entity has 45 days to respond to a written request for data. Further, under Requirement 4.1, if an entity does not provide requested data because, *inter alia*, "providing the data would conflict with the Applicable Entity's confidentiality, regulatory or security requirements, the Applicable Entity shall, within 30 calendar days of the written request, provide a written response to the requesting entity specifying the data that is not being provided and on what basis." According to EEI, it is unclear "at what point a transmission provider's obligation to 'cooperate' with the other Party in the formation of a confidentiality agreement or protective order ends, and its obligation as an Applicable Entity to disclose the requested information under either Requirements R1 or R4 begins."[11]

20. Requirement R1 specifies the planning coordinator or balancing authority shall issue a "data request to applicable entities in its area." Applicable entities that are subject to providing data pursuant to Requirement R2 are transmission planners, balancing authorities, load-serving entities, and distribution providers. The transmission providers discussed by EEI may, in fact, be registered as one or more of the NERC functional entities that make up the applicable entities list in MOD-031-1. Requirement R4 includes provisions for an applicable entity to follow if a conflict arises. On this basis, the Reliability Standard appears to be clear. However, EEI's concern that MOD-031-1 is not

[11] EEI Comments at 5.

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clear regarding the compliance obligations of an applicable entity when required to provide data to a balancing authority or planning coordinator pursuant to a data request under the standard may have merit. Further, it may be possible in some circumstances, depending on the terms of the confidentiality provision at play, to provide data pursuant to a non-disclosure agreement. Therefore, rather than attempting to provide the clarification requested by EEI, the Commission directs NERC to consider EEI's concern regarding the compliance obligations of an applicable entity upon receipt of a data request that seeks confidential information in the standard development process when it addresses the directive to clarify that planning coordinators and balancing authorities must provide demand and energy data upon request of a Regional Entity.[12]

21. ITC Companies raises a concern with the inclusion of transmission planners as listed entities from whom the types of data specified may be requested because, according to ITC Companies, many transmission planners have delegated the collection of data to the ISO or RTO in which they are located. ITC Companies requests that the Commission recognize that agreements governing the reporting of demand and energy data such as those existing between ITC's operating subsidiaries and the ISOs/RTOs in which each operates are common, and thus provide that a transmission planner having such an arrangement with an ISO/RTO will be in compliance with data requests it receives under the Requirements R1 and R4. While the language of particular

[12] *See* Order No. 693 FERC Stats. & Regs. ¶ 31,242, at P 188.

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agreements is beyond the scope of the immediate proceeding, we agree with ITC Companies that Requirement R1 provides the flexibility to collect energy data through alternative mechanisms.[13]

IV. Information Collection Statement

22. The Paperwork Reduction Act (PRA)[14] requires each federal agency to seek and obtain Office of Management and Budget (OMB) approval before undertaking a collection of information directed to ten or more persons or contained in a rule of general applicability. OMB regulations require approval of certain information collection requirements imposed by agency rules.[15] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of an agency rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

23. Through issuance of this Final Rule, the Commission approves Reliability Standard MOD-031-1. As stated above, the Existing MOD C Standards were approved by the Commission in Order No. 693. All information collection estimates associated with the collection of demand and energy data and subsequent retention were assessed in

[13] *See* NERC Petition at 22, 23.

[14] 44 U.S.C. 3501-3520.

[15] *See* 5 CFR 1320.10.

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Order No. 693 and will not be repeated here. The Reliability Standard expands the actual data to be submitted in two areas: (1) weather normalized annual peak hour actual demand for the prior calendar year if this demand varies due to weather-related conditions (e.g., temperature, humidity or wind speed); and (2) summaries detailed in Requirement R1, Subparts 1.5.4 and 1.5.5. The additional data and summaries will increase reporting and preparation time for some applicable entities. Most entities already normalize their actual demand data based on weather. However, some entities may have a one-time cost of determining the method to "weather normalize" the actual demand data. Accordingly, the information collection costs will consist of an annual cost for all applicable entities and, for a small percentage, additional costs will occur during the first year of implementation.

Public Reporting Burden: Reliability Standard MOD-031-1 requires each "Applicable Entity" to provide the data requested by its planning coordinator or balancing authority in accordance with the data request issued pursuant to Requirement R1.[16] Our estimate below regarding the number of respondents is based on the NERC Compliance Registry as of July 31, 2014. According to the NERC Compliance Registry, NERC has registered 478 distribution providers, 469 load-serving entities, 179 transmission planners and 107 balancing authorities. However, under NERC's compliance registration program, entities

[16] Requirement R1, Subpart 1.1 refers to "Applicable Entities" as the list of transmission planners, balancing authorities, load-serving entities and distribution providers that are required to provide the data.

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may be registered for multiple functions, so these numbers incorporate some double counting. The total number of unique entities that may be identified as a data provider (e.g. applicable entity) in accordance with Reliability Standard MOD-031-1 will be approximately 561 entities registered in the United States as a distribution provider, load-serving entity, transmission planner and/or balancing authority.[17] The Commission estimates the annual reporting burden and cost as follows:

	RM14-12-000 Final Rule					
	Number and Type of Respondents (1)	**Annual Number of Responses per Respondent (2)**	**Total Number of Responses (1)*(2)=(3)**	**Avg. Burden & Cost Per Response (4)**	**Total Annual Burden Hours & Total Annual Cost (3)*(4)=(5)**	**Cost per Respondent[18] (5)÷(1)**

[17] This estimate assumes all of the unique entities will be identified to provide demand and energy data.

[18] The estimated hourly costs (salary plus benefits) are based on Bureau of Labor Statistics (BLS) information (*available at* http://bls.gov/oes/current/naics3_221000.htm#17-0000) for an electrical engineer ($59.62/hour).

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(One-time) Determine method to weather normalize annual peak hour actual demand.	28[19] (DP, LSE, TP and/or BA)[20]	1	28	240 hrs. & $14,309	6,720 hours & $400,646	$14,309
(On-going) Develop summary in accordance w/ Requirement R1, Subparts 1.5.4 and 1.5.5.	561 (DP, LSE, TP and/or BA)	1	561	8 hrs. & $477	4,488 hours & $267,575	$477
TOTAL			589		11,208 hours & $668,221	

Title: FERC-725L, Mandatory Reliability Standards for the Bulk-Power System: MOD Reliability Standards.

Action: Final rule.

OMB Control No: 1902-0261

Respondents: Businesses or other for-profit institutions; not-for-profit institutions.

[19] This value represents the number of entities that have not already determined a method to weather normalize annual peak actual demand data. We estimate approximately 5 percent of the applicable entities fall into this category.

[20] DP = distribution provider, LSE = load-serving entity, TP = transmission planner and BA = balancing authority, are functions the applicable entities perform in conjunction or individually. We estimate the total number of unique entities performing one or more of these functions to be 561.

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Frequency of Responses: One-time and ongoing.

Necessity of the Information: Reliability Standard MOD-031-1 implements the Congressional mandate of the Energy Policy Act of 2005 to develop mandatory and enforceable Reliability Standards to better ensure the reliability of the nation's Bulk-Power System. Specifically, the purpose of the Reliability Standard is to provide authority for applicable entities to collect demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data.

Internal Review: The Commission has reviewed the requirements pertaining to the Reliability Standard for the Bulk-Power System and determined that the approved requirements are necessary to meet the statutory provisions of the Energy Policy Act of 2005. These requirements conform to the Commission's plan for efficient information collection, communication and management within the energy industry. The Commission has assured itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information requirements. Interested persons may obtain information on the reporting requirements by contacting: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, e-mail: DataClearance@ferc.gov, Phone: (202) 502-8663, fax: (202) 273-0873]. Comments on the requirements of this rule may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission]. For security reasons, comments

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should be sent by e-mail to OMB at oira_submission@omb.eop.gov. Comments submitted to OMB should refer to FERC-725L and OMB Control No. 1902-0261.

V. Regulatory Flexibility Act Certification

24. The Regulatory Flexibility Act of 1980 (RFA)[21] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities.

25. The Small Business Administration (SBA) revised its size standard (effective January 22, 2014) for electric utilities from a standard based on megawatt hours to a standard based on the number of employees, including affiliates.[22] Under SBA's new size standards, transmission owners and transmission operators likely come under the following category and associated size threshold: Electric bulk power transmission and control, at 500 employees.[23] The Reliability Standard applies to 561 entities. Comparison of the applicable entities with the Commission's small business data indicates that approximately 249 are small entities.[24] Of these, the Commission estimates

[21] 5 U.S.C. 601-612.

[22] SBA Final Rule on "Small Business Size Standards: Utilities," 78 FR 77,343 (Dec. 23, 2013).

[23] 13 CFR 121.201, Sector 22, Utilities.

[24] The Small Business Administration sets the threshold for what constitutes a small business. Public utilities may fall under one of several different categories, each with a size threshold based on the company's number of employees, including affiliates, the parent company, and subsidiaries. The possible categories for the applicable entities have a size threshold ranging from 250 employees to 1,000 employees. For the analysis

(continued…)

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that approximately five percent, or twelve of these small entities expect to be affected by the new requirements of the proposed Reliability Standard. The Commission estimates that the small entities that will be affected by Reliability Standard MOD-031-1 will incur one-time compliance costs ranging up to $14,309 (i.e. the cost of determining the method of weather normalizing annual peak hour actual demand), plus the annual development of summary narratives in accordance with Requirement R1, Subparts 1.5.4 and 1.5.5, resulting in costs of $477.

26. Accordingly, the Commission certifies that the Reliability Standard will not have a significant economic impact on a substantial number of small entities.

VI. Environmental Analysis

27. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[25] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do

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in this proposed rule, we are using the 1,000 employee threshold for each applicable entity type.

[25] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs., Regulations Preambles 1986-1990 ¶ 30,783 (1987).

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not substantially change the effect of the regulations being amended.[26] The actions proposed herein fall within this categorical exclusion in the Commission's regulations.

VII. Document Availability

28. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

29. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

30. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

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[26] 18 CFR 380.4(a)(2)(ii).

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VIII. Effective Date and Congressional Notification

31. These regulations are effective **[INSERT DATE 60 days after publication in the FEDERAL REGISTER].** The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Document Content(s)

RM14-12-000.DOCX.....1-23

150 FERC ¶ 61,108
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Cheryl A. LaFleur, Chairman;
Philip D. Moeller, Tony Clark,
Norman C. Bay, and Colette D. Honorable.

North American Electric Reliability Corporation Docket No. RR15-2-000

ORDER ON ELECTRIC RELIABILITY ORGANIZATION RELIABILITY ASSURANCE INITIATIVE AND REQUIRING COMPLIANCE FILING

(Issued February 19, 2015)

1. On November 3, 2014, the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), submitted a filing describing the Reliability Assurance Initiative (RAI), in which NERC plans to transition to a risk-based approach for compliance monitoring and enforcement.

2. As discussed below, the Commission approves NERC's implementation of RAI, finding that NERC's overall goal of focusing ERO and industry compliance resources on higher-risk issues that matter more to reliability is reasonable. However, to ensure that NERC implements RAI in a reasonable and transparent manner, and that the Commission will maintain its oversight role in a meaningful manner, the Commission directs, pursuant to section 215(f) of the Federal Power Act (FPA), that NERC submit a compliance filing proposing revisions to the NERC Rules of Procedure that articulate the RAI concepts and programs.[1] Further, as discussed below, the Commission identifies certain conditions as to NERC's implementation and continued development of the risk-based approach for compliance monitoring and enforcement reflected in RAI. In addition, we require NERC to submit an annual report on RAI, to be submitted within one year from the date of the issuance of this order.

[1] 16 U.S.C. § 824o(f) (2012).

I. Background

A. Section 215 and NERC Compliance Monitoring and Enforcement

3. Section 215(c) of the FPA requires the Commission to certify an ERO to develop mandatory and enforceable Reliability Standards, as well as rules to provide fair and impartial procedures for enforcement of such Standards, subject to Commission review and approval.[2] This statutory requirement is reflected in section 39.3 of the Commission's regulations.[3] In addition, section 215(f) of the FPA requires the ERO to file with the Commission for approval any proposed rule or proposed rule change.[4]

B. NERC Compliance Monitoring and Enforcement

4. On February 3, 2006, the Commission issued Order No. 672 to implement the requirements of section 215 of the FPA governing electric reliability.[5] On July 20, 2006, the Commission certified NERC as the ERO, including the approval of the NERC Rules of Procedure (NERC Rules) addressing, among other things, the NERC Compliance Monitoring and Enforcement Program (CMEP).[6] The intent of the ERO compliance program, as noted by the Commission, is to facilitate the "ongoing monitoring of user, owner and operator compliance with Reliability Standards."[7] The Commission specified that the three required components of an ERO compliance program are: (1) a compliance program that includes proactive compliance audits; (2) an investigation program for

[2] 16 U.S.C. § 824o(c)(2)(C).

[3] 18 C.F.R. § 39.3 (2014).

[4] 16 U.S.C. § 824o(f).

[5] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[6] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, at P 299, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030, *order on compliance*, 118 FERC ¶ 61,190, *order on clarification and reh'g*, 119 FERC ¶ 61,046 (2007), *rev. denied sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009). The CMEP is Appendix 4C to the NERC Rules.

[7] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062 at P 293.

alleged violations of Reliability Standards that includes prompt Commission notification of incidents and their dispositions; and (3) a penalty program.[8]

5. On December 20, 2012, the Commission issued an order pursuant to FPA section 215(f) conditionally approving revisions to the NERC Rules of Procedure.[9] Among the revisions approved in the December 20 Order was a proposal to revise section 5.0 and Sanction Guidelines section 2.2 to grant NERC the flexibility to deviate from the standard CMEP procedures so that other approaches to enforcement could be considered and applied where the circumstances warrant such flexibility. In approving NERC's proposed revision, the Commission explained that the new flexibility should be used in "limited circumstances" as a reasonable exercise of NERC's enforcement discretion.[10]

6. On March 15, 2012, the Commission issued an order accepting, with conditions, NERC's petition requesting approval of the Find, Fix, Track and Report (FFT) program to allow NERC to address lesser-risk, remediated possible violations of Reliability Standards through FFT spreadsheet informational filings as opposed to the formal Notice of Penalty process.[11] On June 20, 2013, the Commission issued an order accepting NERC's first annual FFT report and approving five enhancements to the FFT program.[12] Most recently, on September 18, 2014, the Commission issued an order accepting NERC's second FFT annual report, as well as approving the expansion of the FFT program to moderate risk possible violations that meet certain Commission-approved criteria.[13] In approving the expansion of the FFT program, the Commission recognized

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[8] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, at P 293 (citing Order No. 672, FERC Stats. & Regs. ¶ 31,204).

[9] *North American Electric Reliability Corp.*, 141 FERC ¶ 61,241 (2012) (December 20 Order).

[10] *Id*. P 95.

[11] *North American Electric Reliability Corp.*, 138 FERC ¶ 61,193 (2012) (March 15 Order); *order on reh'g*, 139 FERC ¶ 61,168 (2012).

[12] *North American Electric Reliability Corp.*, 143 FERC ¶ 61,253 (2013) (June 20 Order).

[13] *North American Electric Reliability Corp.*, 148 FERC ¶ 61,214 (2014) (September 18 Order) (the expansion of the FFT program to certain moderate risk possible violations followed a pilot program approved by the Commission in the June 20 Order).

the efficiencies that had resulted from the FFT program, but also highlighted situations where NERC and the Regional Entities could improve the risk assessments underlying FFT treatment and provide greater clarity in the information provided to support FFT treatment.[14]

II. Description of NERC's Reliability Assurance Initiative

7. In the November 3 Filing, NERC provides an overview of the specific components of RAI. NERC explains that RAI was developed to transition the ERO Enterprise[15] to a risk-based approach for compliance monitoring and enforcement. NERC states that RAI will provide a reasonable assurance of reliability through compliance monitoring, appropriate deterrence through enforcement, and a feedback loop to improve Standards.[16] NERC explains further that this approach benefits reliability, and thereby the public interest, by allowing the ERO Enterprise to focus time and effort on higher-risk issues while still identifying, correcting, and tracking lesser-risk issues.[17]

8. NERC explains that RAI is based upon two separate programs - risk-based compliance monitoring and risk-based enforcement, which are outlined below.

A. Risk-Based Compliance Monitoring

9. NERC outlines four components of risk-based compliance monitoring: (1) Risk Elements Identification; (2) Inherent Risk Assessment (IRA); (3) Internal Controls Evaluation (ICE); and (4) CMEP Tools. NERC explains that, pursuant to the first component - Risk Elements Identification - NERC will regularly identify and prioritize ERO-wide risks to reliability based on "significance, likelihood, vulnerability and potential impact to the reliability of the [Bulk-Power System]," as outlined in NERC's *Risk Elements Guide*.[18] NERC states further that the risk elements will be mapped to related Standards and will be used in developing the ERO's annual CMEP

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[14] September 18 Order, 148 FERC ¶ 61,214 at PP 28 & 30.

[15] "ERO Enterprise" refers to NERC and the eight Regional Entities.

[16] NERC Filing at 1.

[17] *Id.* at 1-2.

[18] *Id.* at 24; *see* http://www.nerc.com/pa/comp/Reliability%20Assurance%20Initiative/Final_RiskElementsGuide_090814.pdf.

Implementation Plan, as well as Regional Entity Implementation Plans, and may be updated on a dynamic basis. NERC explains that this process replaces the Actively Monitored List used in prior years.[19]

10. NERC explains that the second component of risk-based compliance monitoring - IRA - is a review by a Regional Entity of potential risks posed by an individual entity to the reliability of the Bulk-Power System. NERC notes that an IRA considers factors such as assets, system, geography, interconnectivity, prior compliance history and factors unique to the entity. NERC explains that the results of an entity-specific risk assessment may result in the scope of compliance monitoring for a particular entity to include more, fewer, or different Standards than those contained in the ERO and Regional Entity annual CMEP Implementation Plans.[20]

11. The third component of risk-based compliance monitoring outlined by NERC - ICE - is a voluntary evaluation by a Regional Entity of an entity's internal controls that detect, correct, and mitigate the entity-specific risks identified in the IRA. NERC states that the ICE may further refine the scope of an audit, including the depth and breadth of a particular area of review, or determine whether an audit is necessary. NERC states that the result of an ICE may decrease the depth and breadth of a particular area of review if the registered entity demonstrates effective internal controls; however, if a registered entity does not demonstrate effective internal controls for a particular area, the scope will not change from that established in the IRA.[21]

12. NERC explains that when the Regional Entity has reasonable assurance that internal controls are functioning to protect reliability in accordance with the Standards, the Regional Entity may rely on those internal controls and, therefore, extensive testing may not be necessary under the CMEP.[22] NERC notes that there may be instances where, after an IRA has been completed, an entity posing a small inherent risk is only subject to a limited number of applicable Reliability Standards as part of its compliance monitoring scope. In such instances, an ICE may not significantly further tailor the CMEP monitoring activities applied by the Regional Entity, but could provide an opportunity for improvement in controls that could increase reliability and mitigate risks.

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[19] *Id.* at 25.

[20] *Id.* at 26.

[21] *Id.* at 31.

[22] *Id.* at 33.

NERC also notes that the complexity of internal controls is scalable depending on the size of an entity.[23]

13. NERC explains that under the final component of risk-based compliance monitoring - NERC CMEP Tools - a Regional Entity will determine the type and frequency of application of the compliance monitoring tools (e.g., off-site or on-site audits, spot checks or self-certifications) appropriate for a particular registered entity based on its specific reliability risks as evaluated through IRA and, if used, ICE.[24] NERC explains that, while the Regional Entity CMEP implementation plans may indicate the compliance monitoring tools to be used during that implementation year, the Regional Entities will continue to identify appropriate tools to use based on the results of the individual IRAs and ICEs.[25]

B. Risk-Based Enforcement

14. NERC provides a discussion of two primary components of risk-based enforcement: (1) compliance exceptions, and (2) the self-logging process. First, NERC explains that the compliance exception process currently is intended to identify minimal risk instances of noncompliance that do not warrant a penalty, which will be recorded and mitigated without triggering a formal enforcement action under the CMEP. NERC explains further that a "compliance exception is an alternative disposition method and is not a dismissal, FFT, or Notice of Penalty" and, rather, "is essentially the exercise of enforcement discretion…"[26] According to NERC, the compliance exception process builds on the FFT program, but is a distinct enforcement track.

15. NERC states that sections 3.8 and 5.0 of the CMEP provide that an alternative enforcement process such as "compliance exceptions" may be considered and used to

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[23] *Id.* at 30-34.

[24] *Id.* at 34-35.

[25] *Id.* at 34. For example, NERC states, "prior to 2015, Regional Entities conducted audits for all entities on a three- and six-year audit cycle. Using a risk-informed approach, Regional Entities will continue to conduct three-year audits per the [NERC Rules]. However, a registered entity's IRA, and ICE if used, will determine the frequency and Compliance Audit scope rather than a standardized approach[.]" *Id*.

[26] *Id.* at 44. According to NERC, the FFT process will remain an available option for processing matters that do not qualify for compliance exception treatment. *Id*. at 47.

achieve the overall objectives of the compliance program.[27] NERC avers that the proposed compliance exception process under RAI provides such an alternative enforcement process for the resolution of minimal risk noncompliance that is fully consistent with the overall objectives of the CMEP. NERC goes on to explain that a common understanding of the levels of risk is fundamental to the continued evolution of a risk-based enforcement program, outlining the three levels of risk it uses as: "serious and substantial," "moderate," and "minimal." NERC explains that a minimal risk determination will be "based on the combination of the subject Reliability Standard requirement and the attendant facts and circumstances."[28] NERC states that, if nothing serious could have occurred and there were complete or significant protections in place to reduce the risk, the risk assessment would likely be minimal. NERC further states that, if something serious could have occurred and there were only some protections in place to reduce risk, the risk assessment would likely be moderate. NERC adds that "lack of harm is not sufficient justification, by itself, for a minimal or moderate risk assessment."[29] Finally, NERC states that, if an instance of noncompliance is related to a serious event, the risk assessment would likely be serious and substantial.[30]

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[27] As relevant, section 3.8 of the CMEP states that, "If the Preliminary Screen results in an affirmative determination with respect to the above criteria, a Possible Violation exists and the Compliance Enforcement Authority shall proceed in accordance with Section 5.0, unless an alternative enforcement process is used." As relevant, section 5.0 of the CMEP states that, "The following enforcement process is undertaken by the Compliance Enforcement Authority following identification of a Possible Violation of a Reliability Standard Requirement by a Registered Entity. However, under the circumstances presented by some Possible Violations, Alleged Violations or Confirmed Violations, absolute adherence to the following enforcement process, to the exclusion of other approaches, may not be the most appropriate, efficient or desirable means by which to achieve the overall objectives of the Compliance Program for NERC, the Compliance Enforcement Authority and the Registered Entity. In such circumstances, other approaches may be considered and employed. The Registered Entity shall be entitled to object to the use of any such other approach."

[28] NERC Filing at 42-43. According to NERC, the risk analysis is based on prior Commission orders and discussed in the ERO Self-Report User Guide. *Id*. at 42, citing March 15 Order, 138 FERC ¶ 61,193 at PP 44-45.

[29] *Id*. at 43.

[30] *Id. See also id*. at 42, identifying examples of "serious and substantial" issues set forth in the March 15 Order, 138 FERC ¶ 61,193 at P 49.

16. NERC states that it will not publicly post compliance exceptions. Rather, Regional Entities will retain records for each compliance exception and provide NERC a summary of the record. NERC states that although it will not publicly file or post compliance exceptions, the Commission will receive a monthly, non-public spreadsheet with a summary of the record on each compliance exception.[31] NERC explains that it will communicate information regarding the "overall rationale for decisions not to pursue certain matters" through a Compliance Exceptions Overview document that NERC now posts on its website.[32] NERC also commits to submit an annual informational filing to the Commission that would review the progress of the program, discuss appropriate enhancements, provide examples of matters processed as compliance exceptions, and discuss observed trends.[33] Beginning in 2015, similar to its oversight of FFTs, NERC regularly will review a sample of compliance exceptions and provide guidance or adjustments on a prospective basis.[34] NERC states that its annual review of the compliance exception program will consider the inclusion of moderate risk noncompliance in the future.[35]

17. NERC asserts that it is appropriate to treat compliance exceptions as non-public, contending that regulatory agencies, including the Commission, maintain as non-public the existence of ongoing investigations, as well as the decision to close a matter based on the application of enforcement discretion. NERC states that publicly posting compliance exceptions may adversely impact an entity's reputation without making a formal decision regarding a violation. Further, NERC states that posting individual accounts of trivial instances of noncompliance does not provide a benefit, diverts resources that should be allocated elsewhere, and "dilutes the message" provided by the public disposition of higher-risk matters (i.e., the attention drawn to entities involved in high-risk compliance matters is diluted if entities involved in trivial matters are also made public).[36]

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[31] *Id.* at 44.

[32] *See id.* at 50 (referencing NERC's Compliance Exceptions Overview Document, *available at*: http://www.nerc.com/pa/comp/Pages/Reliability-Assurance-Initiative.aspx).

[33] *Id.* at 51.

[34] *Id.* at 55.

[35] *Id.* at 46.

[36] *Id.* at 51-53.

18. Regarding the second component of risk-based enforcement, NERC states that the self-logging process will allow registered entities with demonstrated effective management practices to self-identify, assess, and mitigate minimal risk instances of noncompliance and then record the issue on a log in lieu of individually self-reporting each instance of possible noncompliance. NERC states that a log will contain a detailed description of the issue, the risk assessment, and the mitigating activities completed or to be completed. NERC explains that the Regional Entity will periodically review and approve the log and, once approved, the logged issues typically will be resolved as compliance exceptions.

19. NERC states that participation in the self-logging program is voluntary, and a Regional Entity will determine whether an entity is eligible to self-log. NERC identifies six eligibility criteria for self-logging: (1) the entity's history of initiative and recognition of compliance obligations, (2) reliable and accurate self-reporting of non-compliance, (3) history of timely and thorough mitigation, (4) quality of internal compliance program, (5) cooperation with the Regional Entity during compliance monitoring, enforcement, and Regional Entity outreach activities, and (6) performance during compliance audits. NERC states further that, while an ICE will inform a Regional Entity's decision regarding an entity's participation in the self-logging program, an ICE is not a prerequisite for participation. NERC also explains that a registered entity may be eligible to self-log noncompliance with certain Standards but not others, and that the registered entities may lose eligibility to self-log for various reasons.[37]

20. NERC explains that there are two processes by which a registered entity can qualify for compliance exception treatment. First, NERC states that a Regional Entity can make a case-by-case determination that an instance of noncompliance qualifies as a compliance exception based on the underlying facts and circumstances, including: "what happened, why, where and when;" potential and actual level of risk to reliability; the quality of a registered entity's internal compliance program; and the presence and applicability of aggravating factors, such as repeat or repetitive noncompliance. Second, NERC states that a self-logged compliance matter, described below, is "presumed to be appropriate" for disposition as a compliance exception.[38]

21. NERC states that a compliance exception must be mitigated within twelve months of a Regional Entity notifying an entity that the underlying issue of noncompliance will be resolved as a compliance exception without an enforcement action. NERC adds that,

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[37] *Id.* at 55-64.

[38] *Id.* at 43-54.

similar to FFTs, when a Regional Entity disposes of a matter that has yet to be mitigated as a compliance exception, the record must include the expected completion date for mitigation, the justification for the time required to mitigate an issue, and a description of the compensating measures in place during the period of noncompliance.[39] NERC states further that the failure to mitigate an issue within the established timeframe, or any material misrepresentation, "will result in rescission of the eligibility for compliance exception treatment."[40]

22. NERC explains that a compliance exception is part of an entity's compliance history "only to the extent that it serves to inform the Regional Entity and NERC of the minimal risk issues that are detected and corrected by the entity, and may inform the Regional Entity's decision on how to treat future noncompliance with the same or similar facts."[41] NERC explains that repeat compliance exceptions may not always be indicative of poor performance and may, in fact, be evidence of robust controls in place to detect and correct instances of noncompliance as they occur.[42]

III. Notice of Filing, Interventions, and Comments

23. Notice of NERC's November 3, 2014, filing was published in the *Federal Register*, 79 Fed. Reg. 68,230 (2014), with comments due on or before December 3, 2014.[43] Exelon Corporation filed a timely motion to intervene. American Public Power Association, Electricity Consumers Resource Council, Large Public Power Council, National Rural Electric Cooperative Association, and Transmission Access Policy Group, filing collectively as Joint Commenters; Edison Electric Institute and Electric Power Supply Association, filing collectively as the Associations; and Midcontinent Independent System Operator, Inc. (MISO), filed timely motions to intervene and comments.

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[39] *Id.* at 48.

[40] *Id.* at 49.

[41] *Id.* at 44.

[42] *Id.* at 44.

[43] While NERC styled the submission as an informational filing, the Commission publicly noticed the filing for comment. *Cf.*, *PSEG Energy Resources & Trade LLC*, 134 FERC ¶ 61,080 (2011); *ISO New England, Inc.*, 128 FERC ¶ 61,135 (2009) (Commission acting on pleading titled as informational filing).

24. All commenters support RAI as described in NERC's filing as a means of helping to focus the ERO Enterprise's limited compliance and enforcement resources based on risk to the reliability of the Bulk-Power System. As discussed below, the commenters do not agree, however, on the appropriate level of transparency that should accompany the implementation of RAI. Joint Commenters argue that transparency is necessary, at least for the first two years as RAI is implemented, while the Associations generally argue that greater transparency, in the form of reporting and public posting of self-logging and compliance exceptions, is unnecessary. MISO encourages the Commission to keep compliance exceptions and logs non-public to avoid the risk that registered entities would be more hesitant to report certain issues on their logs.

IV. Discussion

25. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2014), the timely motions to intervene filed by Exelon, Joint Commenters, the Associations, and MISO serve to make them parties to this proceeding.

26. We approve NERC's implementation of RAI, as described in the November 3 filing, agreeing that NERC's overall goal of focusing ERO and industry compliance resources on higher-risk issues that matter more to reliability is reasonable. However, pursuant to section 215(f) of the FPA, we direct NERC to submit a compliance filing that includes proposed revisions to the NERC Rules of Procedure to articulate the RAI concepts and programs.[44] In addition, we set forth certain conditions pertaining to the implementation and continued development of RAI. These conditions are intended to ensure that NERC implements RAI in a reasonable and transparent manner, and that the Commission will maintain a meaningful oversight role, as discussed below. We also require NERC to file an annual report on RAI, the first to be submitted within one year from the date of the issuance of this order, as discussed below.

27. In approving the FFT program, the Commission stated that while "the FFT initiative represents a significant change in the paradigm for monitoring and enforcing compliance with Reliability Standards," experience with NERC's compliance program supported granting "the flexibility to more efficiently process and track lesser-risk violations in order to focus their resources on issues that pose the greatest risk to reliability."[45] NERC's continued experience with compliance monitoring and

[44] 16 U.S.C. § 824o(f).

[45] March 15 Order, 138 FERC ¶ 61,193 at P 1.

enforcement, reflected in noted improvements in NERC's performance,[46] supports the significant shift to the risk-based approach for compliance monitoring and enforcement reflected in RAI. We support an approach to compliance monitoring and enforcement that focuses time and effort on higher-risk issues while still identifying, correcting, and tracking lesser-risk issues.[47]

28. Below, we discuss the following matters: (A) revisions to the NERC Rules of Procedure to articulate the RAI concepts and programs; (B) transparency of the compliance exception process; (C) qualifications for the self-logging program; (D) the treatment of compliance exceptions in an entity's compliance history; (E) finality of compliance exceptions; and (F) annual reporting requirement.

A. Inclusion of RAI Concepts in NERC Rules of Procedure

29. As an initial matter, while we support the objective of the development of the risk-based approach for compliance monitoring and enforcement, we believe that NERC must include fundamental RAI concepts and elements in the NERC Rules of Procedure. We are not persuaded by NERC's filing that the general language regarding "alternative enforcement processes" set forth in sections 3.8 and 5.0 of the CMEP provides an adequate basis for implementing the major shift in approach represented by the RAI framework.[48] NERC's filing indicates that a significant percentage of compliance matters will be processed pursuant to the new compliance exception and logging

[46] *See North American Electric Reliability Corp*., 149 FERC ¶ 61,141 (2014) (noting improvements in NERC's compliance monitoring and enforcement program).

[47] The adoption of the streamlined RAI programs to process lower risk compliance matters suggest that there may be provisions of Reliability Standards that provide little protection to the reliable operation of the Bulk-Power System, and we support NERC's efforts to identify such provision for proposed retirement. *See Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, Order No. 788, 145 FERC ¶ 61,147 (2013) (approving retirement of requirements that provide little protection for Bulk-Power System reliability or are redundant with other aspects of Reliability Standards).

[48] As explained by NERC, under RAI "the transformation to focus on identifying and prioritizing risks replaces a static, one-size-fits-all list of Reliability Standards and prioritizes functions and Reliability Standards based on risk to determine the appropriate oversight method." NERC Filing at 21.

programs.[49] Yet, unlike other NERC compliance processes, there would be no mention of the RAI processes in the NERC Rules of Procedure. Indeed, in approving proposed revisions to section 5.0 to grant NERC the flexibility to deviate from the standard CMEP procedures where warranted, the Commission stated that it understood that the flexibility granted to NERC through the revised language "would be used under limited circumstances" and "should be limited to a reasonable exercise of NERC's enforcement discretion."[50] The significant changes to compliance monitoring and enforcement reflected in RAI go beyond the scope of what we then understood and intended.

30. We do not believe that the availability of RAI guidance documents and the information provided in NERC's RAI filing, all subject to change without prior Commission notification and approval, provide for adequate Commission oversight and transparency and certainty for others. To be clear, we do not expect NERC to include in the Rules of Procedure detailed procedures that would unduly hamstring the intended flexibility and streamlined processes that are the hallmark of RAI. We do, however, conclude that it is appropriate, both for purposes of maintaining meaningful Commission oversight and ensuring that the ERO has rules that "provide fair and impartial procedures for enforcement…,"[51] that the NERC Rules of Procedure, at a minimum, recognize the existence of the RAI processes, articulate basic RAI concepts and define fundamental RAI elements, and require Commission approval for significant changes in RAI as NERC further develops and implements its risk-based approach.[52]

31. As noted above, FPA section 215(f) requires the ERO to file any proposed rule or proposed rule change with the Commission for review and approval.[53] Therefore, we

[49] *E.g.*, NERC Filing at p. 39, n. 30 (approximately 70 percent of instances of noncompliance posed a minimal risk to the system reliability during 2013 and 2014). NERC indicates that many minimal risk matters are eligible for processing as compliance exceptions and subject to self-logging.

[50] December 20 Order, 141 FERC ¶ 61,241 at P 95.

[51] 16 U.S.C. § 824o(c)(2)(C).

[52] For example, similar to the process that NERC used for the initial FFT program and its subsequent expansions, NERC should provide to the Commission advance notice for Commission consideration any expansion of the compliance exception approach to possible violations that are deemed to present a moderate risk to Bulk-Power System reliability. *See* NERC Filing at 46.

[53] 16 U.S.C. § 824o(f). The Commission will provide public notice of the proposed revisions and opportunity for comment.

direct NERC to submit a compliance filing within 90 days of the date of this order proposing revisions to the NERC Rules of Procedure to articulate the RAI concepts and programs in the CMEP.

32. In addition, NERC states that it is currently developing measures of success to evaluate the risk-based approach to compliance monitoring and enforcement.[54] NERC also asserts that it uses a combination of review processes to ensure that the Regional Entities are implementing the CMEP effectively. We find that NERC's commitment to conduct Regional Entity reviews during the first quarter of 2015 is appropriate in order to ensure the program is implemented properly at its outset.[55] However, we find NERC's plan for oversight beyond these reviews to be lacking in specifics. In its 90-day compliance filing, NERC should provide details on: a) its oversight processes for the RAI program and b) how it intends to measure the success of the risk-based approach to compliance monitoring and enforcement, to include the types of data-driven metrics it will track as the RAI program develops.

B. Transparency of Compliance Exceptions

33. As noted above, NERC states that it will not publicly file or post compliance exceptions but, rather, rely on non-public monthly submissions to the Commission and an annual informational filing that includes, among other things, observed trends and examples of matters treated as compliance exceptions. NERC asserts that it is appropriate to treat compliance exceptions as non-public based on the treatment of investigations and use of enforcement discretion by regulatory agencies, including the Commission, and that publicly posting compliance exceptions may adversely impact an entity's reputation without making a formal decision regarding a violation, especially when associated with trivial instances of noncompliance.

34. The commenters do not agree on the appropriate level of transparency that should accompany the implementation of RAI. Joint Commenters argue that transparency is essential, at least for the first two years as RAI is implemented, "to educating industry to avoid and mitigate noncompliance with reliability standards, and to maintain the credibility of NERC's compliance and enforcement regime."[56] In addition, Joint

[54] *See* NERC Filing at 15.

[55] *See* NERC Petition at 16 ("NERC will conduct Regional Entity reviews during the first quarter of 2015 with the intent of supporting conceptual consistency in the application of the ERO Enterprise's risk-based approach").

[56] Joint Commenters Comments at 9.

Commenters assert that public disclosure of compliance exceptions would neither be an undue burden on NERC, nor an undue intrusion into NERC's enforcement discretion.[57]

35. The Associations, for their part, argue that greater transparency in the form of "more extensive reporting and public posting of self-logging and compliance exceptions" is unnecessary.[58] The Associations assert that the annual report proposed by NERC will provide sufficient information to evaluate the effectiveness of RAI and NERC's exercise of enforcement discretion. The Associations proffer that requiring greater transparency "will discourage use of these important tools and is contrary to the overall RAI principle that compliance and enforcement, and the associated reporting and burden, should be aligned to risk."[59] Likewise, MISO encourages the Commission to keep compliance exceptions and logs non-public to avoid the risk that registered entities would be more hesitant to report on their logs "issues that are ambiguous or issues about which the disposition of the violation is likely to be uncertain."[60]

36. We will require NERC to publicly post compliance exceptions in a manner similar to how FFTs are currently posted.[61] We find arguments that publicly posting compliance exceptions is unnecessary or will discourage entities from taking advantage of the efficiencies of RAI unpersuasive. Public disclosure of compliance exceptions would appear to require only minimal additional resources since information will be compiled monthly in a spreadsheet and provided to the Commission. Moreover, the Commission's requirement for NERC to publicly post FFTs does not appear to have been a burden on registered entities, as NERC states that since 2011, FFTs were used to process over 2,000 instances of non-compliance. Rather, we agree with Joint Commenters that transparency in compliance and enforcement matters is beneficial to educate industry and provide additional oversight of the ERO Enterprise. It also serves to allow interested registered entities and other parties to measure consistency across entities, classes of entities, or Regional Entities, as well as demonstrating the quality of registered entities'

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[57] *Id.* at 10-11.

[58] Associations Comments at 7.

[59] *Id.* at 7.

[60] MISO Comments at 5.

[61] NERC's rationale to not make compliance exceptions public because there is no formal decision regarding a violation under the compliance exception process is similar to the argument the Commission rejected with regard to FFTs. *See* March 15 Order, 138 FERC ¶ 61,193 at P 68.

internal controls programs, particularly an entity's ability to swiftly and effectively identify, assess, and correct possible instances of noncompliance.

37. The Commission has recently addressed the appropriate flexibility and associated transparency for compliance and enforcement actions such as FFTs. Among the enhancements to the FFT program approved in the June 20 Order noted above was a proposal to publicly post FFTs on a common website on a monthly basis, as opposed to NERC submitting a monthly informational filing to the Commission.[62] In approving the public posting of FFTs instead of monthly informational filings, the Commission noted that the proposal "will allow NERC and the Regional Entities to more efficiently report on FFTs."[63] We find that the current flexibility provided to the FFT program reflects the risk associated with the underlying instances of noncompliance, and that treating compliance exceptions in a manner similar to FFTs will provide a reasonable level of transparency with minimum effort.

38. The Commission has also maintained a consistent view with regard to transparency in compliance monitoring and enforcement matters. Specifically, in an order directing NERC to make public the disposition of compliance matters through FFT, the Commission stated:

> Because there may be similarly situated registered entities, public disclosure of the identity of the entity in an FFT informational filing will provide industry with valuable information on compliance issues. Further, public disclosure will make the full information regarding an FFT matter available to state regulators and the public, thus, providing additional accountability and deterrence.[64]

More recently, in an order addressing NERC's five-year performance assessment, the Commission stated that it "expect[s] NERC to continue making information publicly available concerning possible non-compliance (other than those involving physical security or cybersecurity concerns) resolved through any and all processing methods."[65] Thus, requiring public disclosure of compliance exceptions is consistent with

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[62] June 20 Order, 143 FERC ¶ 61,253 at P 38.

[63] *Id*.

[64] *North American Electric Reliability Corp*., 138 FERC ¶ 61,193, at P 68 (2012).

[65] *North American Electric Reliability Corp*., 149 FERC ¶ 61,141, at P 72 (2014).

Commission precedent regarding transparency in ERO compliance and enforcement matters.[66]

39. Accordingly, we condition our approval of NERC's RAI implementation on NERC making information regarding non-CIP and CIP compliance exceptions available to the public on an ongoing basis as currently provided for FFTs.[67]

C. Qualification for Self-Logging

40. As noted above, NERC states that participation in the self-logging program is voluntary, and a Regional Entity will determine whether an entity is eligible to self-log based upon six eligibility criteria. Specifically, NERC states that the criteria for self-logging are: (1) the entity's history of initiative and recognition of compliance obligations, (2) reliable and accurate self-reporting of non-compliance, (3) history of timely and thorough mitigation, (4) quality of internal compliance program, (5) cooperation with the Regional Entity during compliance monitoring, enforcement and Regional Entity outreach activities, and (6) performance during compliance audits. NERC states further that, while an ICE will inform a Regional Entity's decision regarding an entity's participation in the self-logging program, an ICE is not a prerequisite for participation.

41. We find it unreasonable to grant the flexiblity inherent in self-logging without some level of formal review of an entity's internal controls. The concept of self-logging instances of noncompliance represents a significant change in NERC's oversight of registered entities. Registered entities will, in effect, self-regulate compliance with the Reliability Standards with minimal oversight, including the possibility that some

[66] *See North American Electric Reliability Corp*., 116 FERC ¶ 61,062, at P 404 (2006); *North American Electric Reliability Corp*., 138 FERC ¶ 61,193, at P 68 (2012) (finding it reasonable to view the closure of a possible violation in an FFT as a negotiated disposition so as to require its public disclosure as provided in 18 C.F.R. § 39.7(b)(4)).

[67] In addition to the name of the registered entity (for non-CIP compliance exceptions), compliance exceptions should, at a minimum, identify how the matter was identified, mitigated, and resolved (i.e., case-by-case compliance exception or self-logged compliance exception). We presume that all self-logged items should be treated as compliance exceptions unless additional risk factors are involved and, therefore, expect that all self-logged items will be included in the posting. We direct NERC to work with Commission staff to ensure they can review each posting of compliance exceptions in an effective and efficient manner, as the Commission previously provided for FFT postings. *See* June 20 Order, 143 FERC ¶ 61,253 at P 39.

registered entities would not experience a compliance audit for more than six years. While it may be reasonable to scale an entity's ICE based on risk, we do not find it reasonable to grant the level of flexibility inherent in self-logging where a Regional Entity has not confirmed the existence - or quality - of an entity's internal controls.

42. Therefore, we condition our approval of NERC's RAI implementation on NERC requiring some level of formal review of an entity's internal controls before granting the flexibility to self-log instances of noncompliance. NERC should address in its 90-day compliance filing, a methodology for assessing an entity's internal controls and the circumstances under which an alternate methodology will be used in place of an ICE.

43. In addition, it is not clear what basis Regional Entities will use to validate an entity's log of self-identified possible violations, or how such a review would compare to the review of self-reported potential violations. Considering the significant change in compliance and enforcement that could occur with self-logging, we believe that it is worthwhile to have some level of standardization of the content and review of an entity's compliance logs that would allow for consistency and ease of compilation and comparison - without taking away flexibility or failing to account for differences among entities in their size and approaches to internal controls. Accordingly, we direct NERC to address in its compliance filing the establishment of an appropriate level of standardization for the content and review of an entity's compliance logs.

D. Treatment of Compliance Exceptions in Compliance History

44. We accept NERC's proposal that compliance exceptions not be included in a registered entity's compliance history for penalty purposes. However, we believe that there is one specific scenario in which an entity's history of compliance exceptions would be directly relevant. In particular, earlier compliance exceptions may be relevant to an entity's compliance history where a later violation classified as "serious" and/or "substantial" follows or occurs because of the entity's unsuccessful or partial remediation of the compliance exception(s), or remediation of the compliance exception(s) reasonably could have enabled the entity to prevent the later serious or substantial violation, but did not.[68] In such situations, a matter treated as a compliance exception relates to a later serious or substantial violation, indicating that the registered entity failed to remediate the

[68] The latter situation could occur, for example, with respect to a transmission owner's compliance exception for FAC-008-3 by rating a transmission line inconsistently with its facility ratings methodology if another of the entity's transmission lines later sagged into a tree, causing a serious violation of FAC-003-2, because the entity failed to rate the other line consistent with its facility ratings methodology.

compliance exception or prevent similar violations, or that its response otherwise was insufficient or too limited in scope.[69] The facts relating to the entity's prior compliance exceptions may be relevant to the later violation and, as such, may inform any enforcement action associated with the later "serious" and/or "substantial" violation.[70]

45. Based on the same rationale, we condition our approval on the relevant Regional Entity assessing any subsequent noncompliance of the same or closely-related Standards and Requirements to determine whether the registered entity should continue to qualify for compliance exception treatment regarding the subject of the repeat noncompliance.[71] While we recognize that subsequent noncompliance of the same or closely-related Standards and Requirements in and of itself should not disqualify an entity from RAI, repeat noncompliance could be indicative of shortcomings in an entity's internal controls or other serious concerns. This understanding appears to be consistent with NERC's, as NERC recognizes that an entity's history of compliance exceptions "… may inform the Regional Entity's decision on how to treat future noncompliance with the same or similar facts."[72]

46. Accordingly, we condition our approval of RAI on having NERC and the Regional Entities: (1) consider a history of compliance exceptions where the failure to fully remediate the underlying compliance matter contributes to a subsequent serious and/or substantial noncompliance matter; and (2) assess subsequent noncompliance to

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[69] C*f.* March 15 Order, 138 FERC ¶ 61,193 at P 64 (In discussing how an FFT would be factored into a registered entity's compliance history, the Commission observed, "[A]nalysis of a poor compliance history may reveal, for example, shortcomings in the registered entity's training program [.]")

[70] Violations that are serious or substantial are more concerning on a risk basis than other violations. Also, consistent with what we have explained previously, the categorization as serious or substantial should depend on risk and compensating measures at the time of the violation, not on after-the-fact determinations of actual harm. September 18 Order, 148 FERC ¶ 61,214 at P 26.

[71] *See North American Electric Reliability Corp*., 132 FERC ¶ 61,182, at PP 5-8 (2010) (providing guidance to NERC and Regional Entities on assessing compliance history for an entity's prior violations of the same or closely-related Reliability Standards and requirements).

[72] NERC Filing at 44. We also agree with NERC's statement that repeat violations could be due in some instances to a registered entity's use of robust internal controls to detect and correct violations as they occur. *See supra* P 22.

determine whether an entity should continue to qualify for compliance exception treatment, as described above.

E. Finality of Compliance Exceptions

47. We recognize that the transition to a risk-based approach for compliance monitoring and enforcement reflects an expansion of NERC's enforcement discretion. The Commission retains its independent enforcement authority pursuant to FPA section 215(e)(3), and this includes further review of a compliance exception after it has been reported to the Commission.[73] In recognition of the need to bring finality to matters addressed through the RAI process, we adopt a time limit for Commission review of compliance exceptions similar to the treatment of FFT informational filings.[74] Specifically, the Commission will consider a compliance exception to be closed sixty days after the compliance exception is reported to the Commission, subject to the limitations outlined below.

48. First, we will not reopen a compliance exception for review unless the Commission provides notice during the sixty-day period that it will review a specific matter. As is the case with the Commission review of FFTs, the sixty-day period is necessary given the possibility that a large number of compliance exceptions could be filed each month. However, the Commission expects to exercise its authority to review compliance exceptions infrequently and only in limited and rare circumstances, such as in situations where the described remedial action does not appear to mitigate the underlying noncompliance, where an event that appears to have posed more than a minimal risk to the reliability of the Bulk-Power System was processed as a compliance exception, or where the Commission determines that there was a pattern of non-compliance and NERC has not adequately explained why the matter is appropriate for compliance exception treatment. Where the Commission initiates a review of a compliance exception, the Commission will review it in a timely manner, but is not committing to complete each review within the sixty-day period. In addition, the Commission retains the discretion to review a compliance exception reported to the Commission even after the sixty-day period if it finds that compliance exception treatment was obtained based on a material misrepresentation of the facts underlying the compliance exception.[75]

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[73] 16 U.S.C. § 824o(e)(3).

[74] *See* March 15 Order, 138 FERC ¶ 61,193 at PP 71-72.

[75] *Id*. P 72.

F. Annual Filing

49. NERC states that it will make an annual informational filing with the Commission "reviewing the progress of the [RAI] program and considering any enhancements or expansions that may be necessary."[76] NERC states further that the informational filing would include observed trends by standard, region or other categories, as well as examples of matters treated as compliance exceptions. We find the annual report content suggested by NERC reasonable and direct NERC to submit an informational filing on RAI, including the information outlined in NERC's November 3 filing, with the Commission annually, along with the following items.

50. The annual report should also address the interplay between the RAI program and other NERC program areas. One important example would be the feedback loop that NERC describes from RAI to the Reliability Standards development process.[77] NERC should explain the feedback process and give examples of how compliance or enforcement matters influenced the process. Another such area of interest is the analysis of Bulk-Power System events. NERC has previously stated that "[t]he anatomy of major disturbances, such as the August 2003 Blackout, reveals it is often a combination of relatively lesser mistakes and problems occurring simultaneously that precipitate a major disturbance."[78] NERC should address how RAI enables NERC to focus attention on such events as indicators of this type of reliability risk and identify resulting actions taken to identify and mitigate the types of minor mistakes or problems known to be causal of major events.

51. The annual report should also address whether a baseline audit is needed to properly evaluate a registered entity's internal controls. NERC provides two examples from the Midwest Reliability Organization[79] that do not clearly explain whether the review of internal controls under ICE is based only on a review of program documents, or whether the review also examines the effectiveness of the program, i.e., a baseline evaluation of actual compliance performance under the entity's internal controls. A process that reviews both program documentation and the actual effectiveness of a

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[76] NERC Filing at 51.

[77] *Id.* at 19.

[78] *Petition Requesting Approval of New Enforcement Mechanisms*, Docket No. RC11-6-000, at 12 (September 30, 2011).

[79] NERC Filing at 32-33.

program may be appropriate to ensure adequate compliance with the risk-based oversight under RAI.

52. The annual report should address and provide an update on NERC's oversight of the RAI program (e.g. whether RAI has been implemented in a consistent manner across the Regional Entities). In addition, the annual report should address and provide an update on the metrics that NERC has or will employ to measure the effectiveness of the RAI program.[80] Finally, the annual report should also address and provide examples of how a Regional Entity assesses and factors into a registered entity's risk assessment and audit scope that entity's use of NERC Alerts, Lessons Learned, Reliability Guidelines, and other NERC learning tools.

The Commission orders:

(A) The Commission hereby accepts NERC's implementation of RAI, subject to conditions, as set forth in the body of this order.

(B) NERC is hereby directed to make a compliance filing within 90 days of the date of issuance of this order, as discussed in the body of this order.

(C) NERC is hereby directed to file an annual report on RAI, the first to be submitted within one year from the date of the issuance of this order, as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

[80] *Id*. at 15 (NERC "...is currently developing measures of success to evaluate the risk-based approach to compliance monitoring and enforcement").

150 FERC ¶ 61,105
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Cheryl A. LaFleur, Chairman;
Philip D. Moeller, Tony Clark,
Norman C. Bay.

Tilden Mining Company L.C. Docket No. EL14-103-000
Empire Iron Mining Partnership

v.

Midcontinent Independent System Operator, Inc.
Wisconsin Electric Power Company

Michigan Public Service Commission Docket No. EL14-104-000

v.

North American Electric Reliability Corporation
Wisconsin Electric Power Company

ORDER DISMISSING COMPLAINTS

(Issued February 19, 2015)

1. On September 19, 2014, Tilden Mining Company L.C. and Empire Iron Mining Partnership (together, the Mines) filed a complaint against the Midcontinent Independent System Operator, Inc. (MISO) and Wisconsin Electric Power Company (Wisconsin Electric) (Mines' Initial Complaint) pursuant to sections 206, 306 and 309 of the Federal Power Act (FPA),[1] and Rule 206 of the Commission's Rules of Practice and Procedure.[2] In their Initial Complaint, the Mines ask the Commission to prohibit

[1] 16 U.S.C. §§ 824e, 825e, and 825h (2012).

[2] 18 C.F.R. §385.206 (2014).

Wisconsin Electric from splitting the Wisconsin Electric Local Balancing Authority (WEC LBA)[3] into the WEC LBA and a new Michigan Upper Peninsula LBA without Commission approval, and to prohibit MISO from accepting and implementing the proposed formation of the Michigan Upper Peninsula LBA without a Commission-approved rate filing. On November 14, 2014, the Mines filed a Motion for Leave to File Amended Complaint and Amended Complaint against MISO and Wisconsin Electric (Mines' Amended Complaint).

2. Also on September 19, 2014, the Michigan Public Service Commission (Michigan Commission) filed a similar complaint pursuant to FPA sections 206, 306 and 309, and Rule 206 of the Commission's Rules of Practice and Procedure against NERC and Wisconsin Electric (Michigan Commission's Complaint). In its complaint, the Michigan Commission asks the Commission to reverse NERC's certification of the Michigan Upper Peninsula LBA, or in the alternative, to clarify that such certification will not have an effect on the allocation of System Support Resource (SSR) costs that would otherwise occur under MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff).[4]

3. As described more fully below, the Mines' Initial and Amended Complaints and the Michigan Commission's Complaint are primarily concerned with the effect of the creation of the new Michigan Upper Peninsula LBA on the allocation of costs between Wisconsin and Michigan customers associated with Presque Isle Units 5-9,[5] which has

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[3] We note that the term "Local Balancing Authority" is not a North American Electric Reliability Corporation (NERC)-defined term, but one used only in MISO as part of the MISO's BA/LBA Coordinated Functional Registration with NERC. NERC instead uses the term "Balancing Authority," defined as "[t]he responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time." In this order, we use LBA to refer to both.

[4] The Tariff defines SSR Units as "[g]eneration Resources or Synchronous Condenser Units [(SCUs)] that have been identified in Attachment Y – Notification to this Tariff and are required by the Transmission Provider for reliability purposes, to be operated in accordance with the procedures described in Section 38.2.7 of this Tariff." MISO, FERC Electric Tariff, Module A, § 1.S "System Support Resource (SSR)" (30.0.0). Unless indicated otherwise, all capitalized terms shall have the same meaning given them in the Tariff.

[5] Presque Isle Units 5-9 are located in Marquette, Michigan within the American Transmission Company (ATC) footprint and provide up to 344 MW of capacity. *See*

(continued…)

been designated an SSR by MISO. As such, we address these complaints jointly in this order.

4. Based on our findings in a related order,[6] discussed further below, which is being issued concurrently with this order, we find that once MISO develops a new SSR cost allocation methodology as instructed, the creation of a new Michigan Upper Peninsula LBA will not affect the allocation of SSR costs associated with the Presque Isle SSR Units, and we accordingly dismiss the complaints as moot.[7]

I. Background and Related Proceedings

5. Under MISO's Tariff, market participants that have decided to retire or suspend a generation resource or SCU must submit a notice (Attachment Y Notice), pursuant to Attachment Y (Notification of Potential Resource/SCU Change of Status) of the Tariff, at least 26 weeks prior to the resource's retirement or suspension effective date. During this 26-week notice period, MISO will conduct a study (Attachment Y Study) to determine whether all or a portion of the resource's capacity is necessary to maintain system reliability, such that SSR status is justified. If so, and if MISO cannot identify an SSR alternative that can be implemented prior to the retirement or suspension effective date, then MISO and the market participant shall enter into an agreement, as provided in Attachment Y-1 (Standard Form SSR Agreement) of the Tariff, to ensure that the resource continues to operate, as needed.[8] The SSR agreement is filed with the Commission and specifies the terms and conditions of the service, including the compensation to be provided to the resource. For each SSR agreement filed with the Commission, a separate rate schedule must be filed to provide for the costs identified in the SSR agreement to be recovered from the identified load-serving entity (LSE)

MISO Original SSR Agreement Filing, Docket No. ER14-1242-000, Transmittal Letter, at 2 (filed Jan. 31, 2014).

[6] *Midcontinent Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,104 (2015) (Rehearing Order).

[7] In that order, the Commission also addresses another complaint filed by the Michigan Commission in Docket No. EL15-7-000, in which it argues that MISO's existing Tariff procedures for allocating SSR costs, when applied to the reduced boundaries of the newly created Michigan Upper Peninsula LBA, will produce unjust and unreasonable results. *See id.* P 170.

[8] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,163, *order on reh'g*, 109 FERC ¶ 61,157 (2004).

beneficiaries, consistent with section 38.2.7.k.of MISO's Tariff governing the allocation of such costs.

6. On July 25, 2012, in Docket No. ER12-2302-000, MISO submitted proposed Tariff revisions regarding the treatment of resources that submit Attachment Y Notices. On September 21, 2012, the Commission conditionally accepted MISO's proposed Tariff revisions effective September 24, 2012, subject to two compliance filings due within 90 and 180 days of the date of the order.[9] On July 22, 2014, the Commission conditionally accepted MISO's compliance filing, subject to further compliance.[10]

7. On January 31, 2014, in Docket No. ER14-1242-000, MISO submitted an SSR agreement under its Tariff between MISO and Wisconsin Electric for the purpose of providing compensation for the continued availability of Wisconsin Electric's Presque Isle Units 5-9 as SSR Units (Original Presque Isle SSR Agreement). Also on January 31, 2014, in Docket No. ER14-1243-000, MISO submitted a proposed Rate Schedule 43G under its Tariff, which specified the allocation of the costs associated with the continued operation of Presque Isle Units 5-9 as SSR Units (Original Presque Isle Rate Schedule 43G). At the time of the filing, section 38.2.7.k of MISO's Tariff required that the costs associated with the Original Presque Isle SSR Agreement be allocated to all LSEs within the ATC footprint on a *pro rata* basis.[11] On April 1, 2014, the Commission issued an order accepting the Original Presque Isle SSR Agreement and Original Presque Isle Rate Schedule 43G, suspending them for a nominal period, to be effective February 1, 2014, as requested, subject to refund and further Commission order.[12]

8. The proper allocation of the Presque Isle (and other units') SSR costs has been at issue in a number of recent and on-going Commission proceedings, including in a complaint proceeding filed by the Public Service Commission of Wisconsin (Wisconsin Commission) on April 3, 2014. In that complaint proceeding, the Wisconsin Commission argued that the MISO Tariff's approach to allocating SSR costs within

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[9] *Midwest Indep. Transmission Sys. Operator, Inc.*, 140 FERC ¶ 61,237 (2012), *order on compliance*, 148 FERC ¶ 61,056 (2014) (SSR Compliance Order).

[10] SSR Compliance Order, 148 FERC ¶ 61,056. Compliance filings and requests for rehearing are pending before the Commission in Docket Nos. ER12-2302-003 and ER12-2302-002.

[11] *See* MISO Original Presque Isle Rate Schedule 43G Filing, Docket No. ER14-1243-000, Transmittal Letter, at 3 (filed Jan. 31, 2014).

[12] *Midcontinent Indep. Sys. Operator, Inc*., 147 FERC ¶ 61,004, at P 12 (2014).

ATC, which differed from the cost allocation approach for the rest of MISO, was unjust, unreasonable, and unduly discriminatory.

9. On July 29, 2014, the Commission issued an order that addressed the Wisconsin Commission's objections to MISO's cost allocation provisions.[13] In that order, the Commission found that the MISO Tariff was unjust, unreasonable, unduly discriminatory, or preferential because the ATC SSR *pro rata* cost allocation method, as applied in Presque Isle Rate Schedule 43G, did not follow cost causation principles.[14] The Commission directed MISO to remove the ATC SSR *pro rata* cost allocation provision from section 38.2.7.k of its Tariff, thereby extending to the ATC footprint the general SSR cost allocation Tariff language, which requires MISO to allocate SSR costs to "the LSE(s) which require(s) the operation of the SSR Unit for reliability purposes."[15] The Commission also required MISO to conduct a final load-shed study and submit a compliance filing to align cost allocation for its rate schedule for Presque Isle. In subsequent orders, the Commission required MISO to align cost allocation under the White Pine Rate Schedule 43H and the Second Revised Escanaba Rate Schedule 43 to address the Commission's findings in the Wisconsin Commission Complaint Order.[16]

10. On September 12, 2014, in Docket No. ER14-2860-000, MISO submitted a proposed replacement SSR agreement under its Tariff between MISO and Wisconsin Electric for Presque Isle Units 5-9 (Replacement Presque Isle SSR Agreement) and requested that the Original Presque Isle SSR Agreement be terminated effective October 15, 2014.[17] Also on September 12, 2014, in Docket No. ER14-2862-000,

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[13] *Midcontinent Indep. Sys. Operator, Inc*, 148 FERC ¶ 61,071 (2014) (Wisconsin Commission Complaint Order).

[14] *Id*. PP 59-61.

[15] *Id.* P 66.

[16] *Midcontinent Indep. Sys. Operator, Inc*., 148 FERC ¶ 61,136 (2014) and *Midcontinent Indep. Sys. Operator, Inc*., 148 FERC ¶ 61,116 (2014), respectively.

[17] The Replacement Presque Isle SSR Agreement reflected: (1) a new Attachment Y Notice from Wisconsin Electric indicating its intent to retire, rather than temporarily suspend operation of, Presque Isle Units 5-9; and (2) increased SSR compensation in accordance with the Commission's determination that compensation provided under an SSR agreement should not exceed a resource's full cost of service. The proposed compensation for the fixed costs of keeping Presque Isle Units 5-9 operational under the Replacement Presque Isle SSR Agreement is $8,084,500 per month, for a total of approximately $117 million dollars over the requested term of

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MISO submitted a revised Presque Isle Rate Schedule 43G under its Tariff to reflect the new requested effective date of October 15, 2014. On November 10, 2014, the Commission issued an order accepting the Replacement Presque Isle SSR Agreement, suspending it for a nominal period, to be effective October 15, 2014, subject to refund, setting the cost-related issues for hearing and settlement judge proceedings, consolidating those proceedings with the ongoing hearing and settlement judge procedures established in the Wisconsin Commission Complaint Order, and terminating the Original Presque Isle SSR Agreement.[18] The Commission also noted that revised Presque Isle Rate Schedule 43G includes cost allocation language that involves several issues that have been raised on rehearing and compliance to the Wisconsin Commission Complaint Order.[19] Accordingly, the Commission accepted revised Presque Isle Rate Schedule 43G, suspended it for a nominal period, to be effective October 15, 2014, subject to refund and further Commission order in the Wisconsin Commission Compliant Order rehearing and compliance proceedings.

11. In response to the requests for rehearing on the Wisconsin Commission Complaint Order, as well as to arguments made in compliance proceedings addressing the individual SSR agreements and cost allocation rate schedules applicable to the ATC footprint, we are issuing, concurrently with this order, an order granting, among other things, clarification regarding the appropriate methodology for allocating SSR costs for certain SSRs, including Presque Isle Units 5-9, within the ATC footprint. This clarification has a direct bearing on the instant complaints, as it requires MISO to develop a cost allocation approach for the Presque Isle SSR Units that does not rely on LBA boundaries, as further discussed below.[20]

14.5 months. *See* MISO Replacement Presque Isle SSR Agreement Filing, Docket No. ER14-2860-000, Transmittal Letter, at 2, 13 (filed Sept. 12, 2014) (citing *Midcontinent Indep. Sys. Operator, Inc*., 148 FERC ¶ 61,057, at P 82 (2014)).

[18] *Midcontinent Indep. Sys. Operator, Inc.*, 149 FERC ¶ 61,114 (2014) (November 10 Order).

[19] *Id.* P 78.

[20] Rehearing Order, 150 FERC ¶ 61,104 at PP 2, 80-89.

II. Docket No. EL14-103-000

A. Mines' Initial Complaint Against MISO and Wisconsin Electric

12. The Mines state that they operate iron ore mines near Ishpeming, Michigan and that they are electric customers of Wisconsin Electric. The Mines allege that Wisconsin Electric decided, for economic reasons, to create the new Michigan Upper Peninsula LBA to operate within the Michigan Upper Peninsula, "to change the allocation of SSR costs under MISO's Tariff between customers in Wisconsin and those in the U[pper] P[eninsula] of Michigan."[21] The Mines state that Wisconsin Electric has not provided any evidence that the creation of the new LBA will enhance reliability, maintaining that no new personnel are being hired by Wisconsin Electric to operate the Michigan Upper Peninsula LBA, and that it will continue to utilize the existing Energy Management System. In addition, the Mines note that NERC has denied any authority to address cost allocation issues as part of its review of a request to certify a new LBA.

13. The Mines state that the proposed split of the Wisconsin Electric LBA into the WEC LBA and the Michigan Upper Peninsula LBA will result in a significant shift of SSR costs from Wisconsin ratepayers to ratepayers in the Upper Peninsula of Michigan, with Michigan's total share of Presque Isle SSR costs increasing from 14.31 percent to over 99 percent.[22] The Mines maintain that this kind of cost shifting raises policy concerns, and caution against "the slavish adherence to strict cost-causation principles which are antithetical to, and threaten the Balkanization of, the integrated electric power grid currently serving all electric consumers."[23]

14. The Mines argue that the establishment of the Michigan Upper Peninsula LBA by Wisconsin Electric and the recognition of the new LBA by MISO must be reviewed by the Commission under FPA section 205.[24] The Mines argue that the creation of a new LBA in these circumstances is a rule "affecting or pertaining to" rates and charges of a public utility, and therefore must be shown to be just and reasonable under FPA section 205. Moreover, the Mines argue that MISO's Tariff is unjust and unreasonable because it does not (1) require MISO to obtain Commission approval for a change in LBA boundaries despite the significant impact of such a change on rates, or (2) otherwise

[21] Mines' Initial Complaint at 4.

[22] *Id.*

[23] *Id.* at 5.

[24] *Id.* at 17-18.

provide procedural protections for ratepayers affected when such a change occurs. The Mines make similar arguments with respect to Wisconsin Electric's obligation to seek Commission approval before it can be allowed to create two separate LBAs.

15. The Mines accordingly ask the Commission to (1) prohibit Wisconsin Electric from implementing a separate Michigan Upper Peninsula LBA; (2) prohibit MISO from accepting and implementing the split in LBAs, absent a Commission-approved rate filing; (3) find that MISO's Tariff is unjust and unreasonable; and (4) clarify that neither MISO nor Wisconsin Electric may implement a change in an LBA boundary without Commission approval. In addition, the Mines ask the Commission to make a more general finding that, where formation of a new LBA has significant potential rate consequences, a regional transmission organization may not implement the change in LBA boundaries without Commission consideration and approval of the rate consequences.[25]

B. Notice and Responsive Pleadings to Mines' Initial Complaint

16. Notice of the Mines' Initial Complaint was published in the *Federal Register*, 79 Fed. Reg. 58,764 (Sept. 30, 2014), with interventions and protests due on or before October 9, 2014. Both MISO and Wisconsin Electric submitted timely answers to the Mines' Initial Complaint.

17. Timely motions to intervene were filed by: Wolverine Power Supply Cooperative, Inc. (Wolverine), ATC, the Michigan Public Power Agency (MPPA), Wisconsin Public Service Corp. (WPS), Consumers Energy Company (Consumers), Michigan Electric Transmission Company, LLC (METC), WPPI Energy, the City of Escanaba, Wisconsin Light and Power Co. (WP&L), Cloverland Electric Cooperative (Cloverland), DTE Electric Company (DTE), NERC, Verso Paper Corp. (Verso Paper), Integrys Energy Services, Inc. (Integrys), and the City of Mackinac Island (Mackinac). Notices of intervention were filed by the Michigan Commission and the Wisconsin Commission. On December 4, 2014, Upper Peninsula Power Co. (UPPCo) filed a motion to intervene out-of-time.

18. Substantive comments or protests were filed by: Verso Paper, Integrys, NERC, and a number of individual commenters, largely comprised of Wisconsin Electric retail ratepayers within the Upper Peninsula. In addition, comments were filed out of time by: U.S. Representative Dan Benishek; Michael E. Moody, Assistant Attorney General, Environment, Natural Resources, and Agriculture Division, on behalf of Rick Snyder, Governor of Michigan, Bill Schuette, Attorney General of Michigan, Fred Upton, U.S.

[25] *Id*. at 21-22.

Representative, and Dan Benishek, U.S. Representative (Michigan Representatives).[26] On October 23, 2014, Michigan State Senator Carol M. Viventi, Secretary of the Michigan Senate, submitted Michigan Senate Resolution No. 187, urging the Commission to reverse its decision accepting MISO's revised SSR cost allocation methodology. On November 21, 2014, John C. Procario, Chairman, President and CEO of ATC, submitted a letter regarding electric supply issues in the Upper Peninsula of Michigan.[27]

19. Motions for leave to answer, and answers to the comments, protests, and answers of other entities were filed by Integrys, MISO, Verso Paper, Wisconsin Electric and the Michigan Commission.[28]

1. Answers

20. In its answer to the Mines, MISO first argues that it should be dismissed as a respondent because it has acted in conformity with its Tariff and all statutory and regulatory requirements. MISO maintains that it was "required to recognize Michigan Upper Peninsula's status as an LBA for purposes of SSR cost allocation" once the Michigan Upper Peninsula LBA was certified by NERC.[29] Moreover, MISO argues that

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[26] The comments submitted by the Michigan Representatives provide a history of efforts to address the potential retirement of the Presque Isle plant, including on-going efforts to build replacement generation that would operate at a much lower cost. They also raise concerns about the potential bias towards transmission or reliability-based solutions in the Commission's approach, and urge the Commission to consider alternative, lower-cost solutions.

[27] Mr. Procario's letter was submitted in response to the Michigan Representatives' comments, and provides further background on ATC's transmission planning-related efforts to address the potential retirement of the Presque Isle units, and on on-going transmission projects to increase reliability in the Upper Peninsula.

[28] While several of the answers to answers or comments were submitted after the Mines submitted their Amended Complaint, discussed in Section II.C. below, the arguments contained therein were made in response to arguments and comments filed in response to the Mines' Initial Complaint and are accordingly discussed in conjunction with the comments and protests to the Initial Complaint.

[29] MISO Answer to Mines' Initial Complaint at 2. Further, MISO contends that no authority exists for MISO to file NERC's balancing area certification and reliability decisions whenever they "affect" MISO's rates. MISO states that it is not a regional entity and thus lacks decisional or suspension authority with respect to matters that lie

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any FPA section 205 filing that MISO was required to make in order to reflect the creation of the Michigan Upper Peninsula LBA has been made via its FPA section 205 filing in Docket No. ER14-2952. Second, MISO maintains that the Mines are trying to relitigate MISO's already accepted methodology for allocating SSR costs, including a Commission order that MISO characterizes as confirming that "allocating SSR costs through LBAs is a permissible application of the Tariff."[30] MISO argues that the Commission has already determined that MISO has considerable flexibility in deciding on the methodology for the allocation of SSR costs to the LSEs that require the operation of the SSR Unit for reliability purposes; and using LBA allocation based on an optimal load-shed study is a just and reasonable application of Section 38.2.7.k, which is consistent with cost causation.[31]

21. MISO argues that the Mines are active participants in other pending proceedings in which other aspects of the Presque Isle SSR Agreement are at issue. Further, MISO argues that the Mines have not provided any basis to find the MISO Tariff unjust and unreasonable, and describes its Tariff, other approved governing documents (i.e., the Balancing Authority Agreement), and the FPA as setting out a "framework that clearly separates reliability matters from tariff and rate regulation."[32]

22. MISO also argues that there is no need for the tariff revisions proposed by the Mines because the MISO Tariff provides appropriate flexibility in allocating SSR costs, including a process that provides adequate notice and opportunity for parties to comment. Along these lines, MISO notes that its SSR cost allocation filing reflecting the formation of the Michigan Upper Peninsula LBA is pending before the Commission. Additionally, MISO contends that going beyond these existing procedures would unreasonably expand FPA section 205's filing requirement and is inconsistent with the just and reasonable contractual and regulatory framework that governs the relationship between MISO and its LBAs.[33]

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within NERC's purview, including balancing area certification, and that it otherwise has no grounds to challenge NERC's processes.

[30] *Id.* at 3 (citing SSR Compliance Order, 148 FERC ¶ 61,056 at P 49).

[31] *Id.* at 16.

[32] *Id.* at 4.

[33] *Id.*

23. In its answer, Wisconsin Electric maintains that the issues raised by the Mines' Initial Complaint are all pending before the Commission in other dockets.[34] Wisconsin Electric also argues that a change in LBA boundaries should not change the LSEs to which SSR costs are allocated. In addition, Wisconsin Electric responds to the Mines' arguments regarding the potential "Balkanization" of the grid that could result if reliability costs are not appropriately socialized by arguing that the Mines fail to provide any rationale or record support for a deviation from longstanding Commission policy regarding cost causation, beyond their claim that they will have to pay more.[35] Wisconsin Electric further argues that the Presque Isle SSR costs are generation costs, not transmission costs, and that any broad-based change in the Commission's approach to SSR cost allocation should be taken up in a rulemaking proceeding. Wisconsin Electric also argues that NERC has no responsibility with respect to cost allocation and that the Commission should acknowledge that MISO is not responsible for the certification of LBAs.[36]

24. In addition, both Wisconsin Electric and MISO contend that the Mines' Initial Complaint represents an attempt to re-litigate SSR cost allocation issues that either have been decided or are pending in other Commission proceedings. Accordingly, they argue that the parts of the Mines' Initial Complaint regarding the appropriateness of socialization of reliability costs are collateral attacks against previous Commission determinations, for which the Mines have had opportunity to request rehearing.[37] Wisconsin Electric contends that the Mines have not demonstrated why the existing proceedings are inadequate to address these concerns, such that its complaint should not be dismissed. Wisconsin Electric also argues that establishing a separate, yet redundant

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[34] Wisconsin Electric Answer to Mines' Initial Complaint at 2. However, Wisconsin Electric also takes the position that the Mines failed to protest MISO's compliance filing in Docket No. ER14-1243-004, and are trying to correct that oversight via this complaint. *Id.* at 6.

[35] *Id.* at 5.

[36] *Id.* at 15.

[37] MISO Answer to Mines' Initial Complaint at 15-16 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 148 FERC ¶ 61,057 at P 159; Letter order, Docket Nos. ER14-109-000 & ER14-111-000 (Dec. 12, 2013); Letter order, Docket Nos. ER14-112-000 & ER14-113-000 (Dec. 12, 2013)), Wisconsin Electric Answer to Mines' Initial Complaint at 4-5.

rate proceeding addressing the same cost allocation matter is administratively inefficient and unreasonable.[38]

2. Comments, Protests and Subsequent Answers

25. Verso Paper and Integrys filed comments in support of the Mines' Initial Complaint, the Wisconsin Commission filed comments that generally oppose the Mines' arguments and requested relief, and NERC filed limited comments seeking to clarify its role in the certification process for the new Michigan Upper Peninsula LBA. In addition, numerous ratepayers made filings in support of the Mines' Initial Complaint, citing the potential economic hardship incurred by Michigan Upper Peninsula customers based on the LBA split and providing individual estimates of the expected increase in costs resulting from the reallocation of Presque Isle SSR costs.[39]

26. Integrys supports the Mines' arguments and requested relief, and argues that Wisconsin Electric is exploiting a "regulatory gap," with NERC asserting that its review is limited and MISO asserting that it lacks authority to review the proposed LBA. Integrys argues that Wisconsin Electric has used this regulatory gap to unilaterally reallocate Presque Isle SSR costs to Upper Peninsula distribution customers.[40] Integrys agrees with the Mines that it cannot be just and reasonable for a utility to be able to reallocate millions of dollars of costs without regulatory oversight and a determination that the new rate and cost shifts are just and reasonable.[41] In addition, Integrys asserts that Wisconsin Electric's customers are "being forced to pay for the costs caused not by them, but caused by the failure of Wisconsin Electric and ATC to reinforce the transmission system in the Upper Peninsula."[42] Integrys further notes that Wisconsin Electric already recovers costs for the Presque Isle units in its retail rate base, and points

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[38] Wisconsin Electric Answer to Mines' Initial Complaint 6-7.

[39] *See* Comments of Mackinac Island, Pinecrest Medical Care Facility, CCI Systems, Gina M. Harman, KHP Properties, LLC, Sangola Hardwoods, Inc., Northwoods Manufacturing Inc., Chris Harman, Conrad Stromberg, Dickenson County Healthcare System, Jim Myllyla, William Becker, Therese Kucharczyk, Darell J. Orman, Tina M. Perry, and Charles Perry.

[40] Integrys Comments at 5.

[41] *Id.* at 7.

[42] *Id.*

out that such generating costs are generally allocated 92 percent to Wisconsin customers and eight percent to Michigan customers.

27. Integrys also questions MISO's studies establishing the need for all of Presque Isle Units 5-9 to serve as system support, as the studies failed to consider Load Modifying Resources (LMR) registered with MISO. Specifically, Integrys argues that MISO failed to consider two LMRs that would total approximately 240 MW of the 300 MW of load that would be located in the proposed Michigan Upper Peninsula LBA.[43] Finally, Integrys argues that the Michigan Upper Peninsula LBA is too small and isolated an area to be treated as a separate LBA for cost allocation purposes, as the increased costs may trigger a loss of a large customer's load, forcing the remaining customers to bear an even higher share of the Presque Isle costs.[44]

28. Verso Paper agrees with the Mines that Wisconsin Electric has improperly used the NERC process "to gerrymander its LBA for the sole purpose of significantly shifting costs" to the Upper Peninsula of Michigan.[45] Verso Paper further agrees that the formation of the Michigan Upper Peninsula LBA is subject to the Commission's FPA jurisdiction as a matter affecting rates, and focuses much of its discussion on the Commission's standard for determining whether a given matter is subject to FPA section 205 jurisdiction.

29. In its comments, the Wisconsin Commission maintains that the appropriate forums for resolving the complainants' issues are the ongoing Commission proceedings that relate to the allocation of Presque Isle SSR costs. Moreover, the Wisconsin Commission asserts that "LBAs are mechanisms for allocating responsibility for reliability functions, and as such, have no intrinsic connection to cost allocation."[46] Instead, the Wisconsin Commission argues, MISO's "decision" to use LBAs to allocate SSR costs is one that was not required by its Tariff, and is only one of a number of methodologies that MISO could have chosen.[47]

30. In its limited comments on the Mines' Initial Complaint, NERC seeks to clarify that it did not "approve" Wisconsin Electric's proposal to split into two LBAs, but merely

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[43] *Id*. at 9-10.

[44] *Id*. at 11-12.

[45] Verso Paper Comments at 4.

[46] Wisconsin Commission Comments at 6.

[47] *Id.*

certified the Michigan Upper Peninsula LBA in accordance with its Rules of Procedure. NERC maintains that under those rules, its role is to ensure that entities are technically capable of performing their functions so as to better ensure reliability, and that cost allocation issues are beyond the scope of its jurisdiction.[48]

31. On October 24, 2014, MISO filed a motion for leave to answer and answer to Integrys's comments on MISO's failure to consider LMRs as part of its Presque Isle SSR studies. MISO argues that Integrys's arguments are an impermissible collateral attack on prior Commission rulings on MISO's studies. In addition, MISO argues that an LMR may not be used in the way that Integrys suggests. MISO maintains that even if registered with MISO, an LMR does not meet the criteria set forth by the Commission and the Tariff for including it as an offsetting, or alternative, resource to an SSR agreement, because LMRs must have "additional firmness of commitment" through "contractual assurances" and, for demand-side resources, "protocols for responding to Transmission Provider instructions."[49]

32. Integrys also filed a motion for leave to answer and answer on October 24, 2014, in response to Wisconsin Electric's Answer to the Mines' Initial Complaint. Integrys argues that Wisconsin Electric is effectively collaterally attacking the Commission's prior orders on MISO's SSR cost allocation methodology by continuing to put forward its preferred cost allocation theory, i.e., arguing for an allocation based on commercial pricing nodes rather than LBAs or LSEs. Integrys also argues that the use of commercial pricing nodes to allocate SSR costs is impractical, since the amount of energy withdrawals for a given LSE cannot be determined by the commercial pricing node alone. Moreover, Integrys argues that use of commercial pricing nodes to allocate costs only for Wisconsin Electric would be unduly discriminatory when MISO does not use that methodology to allocate costs for any other LSE.

33. On November 14, 2014, Verso Paper filed an answer in response to "various pleadings" filed in the Mines' Initial Complaint proceeding and related dockets, addressing two issues. First, Verso Paper makes a general argument regarding appropriate SSR cost allocation, advocating for an approach that would allocate costs similarly to the way costs are recovered when a plant is included as a state regulated asset (with Wisconsin customers paying 92 percent of Presque Isle's SSR costs and Michigan customers paying approximately eight percent). Verso Paper argues that the Presque Isle units continue to be owned by Wisconsin Electric and operated to provide bundled service and that Wisconsin Electric has an obligation to serve both its bundled retail

[48] NERC Comments at 3.

[49] MISO Oct. 24 Answer at 8-9.

choice customers and its Michigan retail choice customers. In addition, Verso Paper disagrees with Wisconsin Electric's statement that it is "undisputed" that MISO has correctly identified the LSEs that benefit from the Presque Isle SSR units.[50] Verso Paper states that it has disputed MISO's load-shed study on at least three occasions, with no substantive response from MISO.[51]

34. On December 2, 2014, Wisconsin Electric filed a motion for leave to answer and answer in response to Verso Paper's answer. In addition to its procedural objections to Verso Paper's answer, Wisconsin Electric provides a substantive response to Verso Paper's arguments on MISO's allocation of SSR costs and its related load-shed study, maintaining that the Commission has already established that recovery of SSR costs is appropriate.[52] In addition, Wisconsin Electric argues that the LBA split should not result in a reallocation of SSR costs if MISO were using an allocation methodology that was consistent with its Tariff.[53]

35. On December 17, 2014, the Michigan Commission filed a motion for leave to answer and answer to Wisconsin Electric's answer to Verso Paper. The Michigan Commission argues that Verso Paper's concerns regarding the load-shed study, and similar concerns expressed by the Michigan Commission, are not collateral attacks on the Wisconsin Commission Complaint Order, as Wisconsin Electric claims in its comments.[54] The Michigan Commission adds that such concerns relate to the assumptions built into the load-shed study and that such implementation details were not the subject of the Wisconsin Commission Complaint Order.[55] Finally, the Michigan Commission argues that Wisconsin Electric's position that the allocation of SSR costs should not go beyond the "load pocket" area identified by the load-shed study is a collateral attack on the Wisconsin Commission Complaint Order, which expressly

[50] Verso Paper Nov. 14 Answer at 6-7 (citing Wisconsin Electric November 3 Answer at 4).

[51] *Id.* at 7-8.

[52] Wisconsin Electric Dec. 2 Answer at 5.

[53] *Id.* at 6.

[54] Michigan Commission Dec. 17 Answer at 2-3.

[55] *Id.* at 3.

requires MISO to allocate SSR costs to "the LSE(s) which require(s) the operation of the SSR Units for reliability purposes."[56]

36. The Michigan Commission contends that by focusing on the issue of load pockets, Wisconsin Electric is attempting to sidestep the issue of voltage and thermal contingencies, which would be caused by SSR unit retirements. By looking at thermal contingencies, according to the Michigan Commission, the costs would be allocated heavily to regions other than the Michigan Upper Peninsula, such that allocation by load pockets, as advocated by Wisconsin Electric, would be unjust and unreasonable.[57]

C. Mines' Amended Complaint

37. On November 14, 2014, the Mines filed the Mines' Amended Complaint. In support of their motion for leave to amend, the Mines note that they could file a new complaint in a separate docket to address the issues they seek to raise, but argue that the interrelated nature of the issues raised in their Initial and Amended Complaints favor their being considered as part of one proceeding.[58]

38. As a substantive matter, the Mines' Amended Complaint questions whether MISO's Replacement Presque Isle SSR Agreement with Wisconsin Electric, filed in Docket No. ER14-2860-000, is valid or whether "it is merely an artifice, designed to enable [Wisconsin Electric] to double-recover costs that are already fully recovered through other regulatory tariff rate mechanisms."[59] The Mines argue that Wisconsin Electric cannot cease operations at the Presque Isle plants without regulatory approvals from Michigan and Wisconsin; therefore, the Mines argue, termination of operations at Presque Isle cannot be "imminent."[60] In addition, the Mines argue that the Replacement

[56] *Id.* (citing Wisconsin Commission Complaint Order, 148 FERC ¶ 61,071 at P 66 and Section 38.2.7.k of MISO's Tariff).

[57] *Id.* at 4-6 (citing Attachment Y Study dated August 15, 2014, Appendix A, Table 13a: Compare Thermal Results; ATC "2014 10-Year Assessment Projects" Planning Zones 1-3).

[58] Mines' Amended Complaint at 2.

[59] *Id.* at 5.

[60] *Id.* at 6.

Presque Isle SSR Agreement is invalid because Presque Isle's costs can be recovered through existing rate structures.[61]

39. The Mines also argue that if an SSR cost allocation based on the split LBA can be effectuated without any kind of Commission approval, as MISO and Wisconsin Electric assert, then the Commission's exclusive FPA section 205 jurisdiction would be circumvented.[62] The Mines assert, as they did in their Initial Complaint, that there is no reliability-based justification for the proposed split of the Wisconsin Electric LBA, and that the new allocation of SSR costs would increase Michigan's share of SSR cost responsibility from 14.31 percent to over 99 percent.[63]

40. The Mines maintain that MISO violated its Tariff by accepting the Replacement Presque Isle SSR Agreement at issue because (1) Wisconsin Electric may not lawfully terminate operations at the Presque Isle plant without regulatory approvals; (2) MISO did not properly evaluate whether an SSR agreement is necessary to ensure continued operations; and (3) there is no economic justification for Wisconsin Electric to terminate operations at the Presque Isle plant because Wisconsin Electric's costs "are already recovered as embedded costs in Wisconsin Electric's regulated retail and wholesale rates."[64] The Mines make similar arguments in support of their requested relief against Wisconsin Electric, arguing that the Commission should find that the Replacement Presque Isle SSR Agreement is invalid, unjust and reasonable. The Mines also ask that the Commission order MISO not to pay Wisconsin Electric's SSR costs under the Replacement Presque Isle SSR Agreement and to refund any SSR costs already collected.

D. Notice and Responsive Pleadings to Mines' Amended Complaint

41. Notice of the Mines' Amended Complaint was published in the Federal Register, 79 Fed. Reg. 70,516-02 (Nov. 26, 2014), with comments and protests due on or before December 4, 2014. MISO and Wisconsin Electric filed timely answers to the Mines' Amended Complaint.

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[61] *Id.* at 9.

[62] *Id.* at 11-12.

[63] *See id.* at 19.

[64] *Id.* at 22.

Answers

42. MISO, in its answer to the Mines' Amended Complaint, states that the correct venue in which to consider SSR costs is within the hearing and settlement procedures established in the November 10 Order or within a request for rehearing for that order. Additionally, MISO argues that many of the arguments in the Mines' Amended Complaint were addressed in that proceeding, rendering them collateral attacks against the November 10 Order.[65] MISO states that the Commission conditionally accepted the Replacement Presque Isle SSR Agreement in the November 10 Order, contrary to the Mines' assertion that the Replacement Presque Isle SSR Agreement is invalid and not just and reasonable.[66] MISO states that the November 10 Order addresses all of the issues now raised by the Mines regarding the validity of Presque Isle as an SSR, including the required regulatory approvals for retirement of Presque Isle and the effect of that retirement on reliability. MISO argues that the Mines overlook the essential reliability benefits derived from Presque Isle when they claim that existing cost recovery mechanisms are sufficient to cover Presque Isle's continued operation, and Wisconsin Electric cannot be required to operate Presque Isle in the absence of an SSR agreement, which MISO states is also noted in the November 10 Order.[67] Further, MISO states that "[t]his need to support the bulk electric system is the trigger to the Commission's authority to approve MISO's determination that the continued service of [Presque Isle] is required."[68]

43. In its answer to the Mines' Amended Complaint, Wisconsin Electric argues that the Mines have not provided sufficient evidence to demonstrate that the Replacement Presque Isle SSR Agreement is unjust and unreasonable under FPA section 206, and accordingly request that the Mines' Amended Complaint be rejected.[69] Wisconsin Electric also argues that dismissal of the Mines' Amended Complaint is needed to avoid

[65] MISO Answer to Mines' Amended Complaint at 9-10.

[66] *Id.* (citing November 10 Order, 149 FERC ¶ 61,114 at P 24).

[67] *Id.* at 8 (citing November 10 Order, 149 FERC ¶ 61,114 at P 39).

[68] *Id.* at 9 (citing 16 U.S.C. § 824(b)(1) ("not have jurisdiction . . . over facilities for generation of electric energy. . .")).

[69] Wisconsin Electric Answer to Mines' Amended Complaint at 4-5.

undue delay in the proceeding, and undue burden on the many parties that have already commented on the Mines' Initial Complaint.[70]

44. Wisconsin Electric states that the new claims raised by the Mines are currently before the Commission in other proceedings, including arguments regarding the need to secure regulatory approvals to retire Presque Isle. Specifically, Wisconsin Electric notes that it has explained that whether facilities are approved as SSRs is subject to the Commission alone, and no Michigan law requires that the Michigan Commission approve Wisconsin Electric's decision to retire a facility. Wisconsin Electric also clarifies that it has the right to retire the Presque Isle units because it has sufficient resources to perform its duties and meet customer demand without the Presque Isle units. Wisconsin Electric also states that MISO has approved Presque Isle as an SSR, and that the Commission has found that MISO properly conducted the SSR study and procedures.[71]

45. Regarding the Mines' claim that the SSR agreement will lead to double recovery of the costs of the Presque Isle plant, Wisconsin Electric states that it has explained in a previous proceeding that the Mines' assertion is incorrect. First, Wisconsin Electric states that the Commission has stated that "all SSR units should be fully compensated for any costs incurred because of their extended service."[72] Second, Wisconsin Electric contends that retail jurisdiction proceedings, and not the Commission, will serve to ensure that double recovery does not occur. Third, Wisconsin Electric states that under the SSR Agreement, market revenues serve to offset the costs associated with the SSR Agreement. Consequently, if market revenues provide full recovery of the revenue requirements detailed in the SSR Agreement, then the SSR costs are covered and the costs to LSEs would be zero. Finally, Wisconsin Electric states that the Commission has already set cost compensation issues for hearing and settlement judge procedures, and, because the Mines do not provide any additional evidence in their Amended Complaint, there is no reason for the Commission to consider this issue in two separate proceedings. As such, Wisconsin Electric requests that the Mines' Amended Complaint be dismissed.[73]

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[70] *Id.* at 5-7.

[71] *Id.* at 7-8.

[72] *Id.* at 9.

[73] *Id.* at 8-10.

III. Docket No. EL14-104-000

A. Michigan Commission's Complaint Against NERC and Wisconsin Electric

46. On September 19, 2014, the Michigan Commission filed a complaint against both NERC and Wisconsin Electric, objecting to NERC's certification of the Michigan Upper Peninsula LBA as a new LBA. The Michigan Commission requests that the Commission reverse NERC's certification of the Michigan Upper Peninsula LBA, or, in the alternative, that the Commission "make clear that NERC's approval of a split LBA will not have any impact upon the allocation of SSR costs that would otherwise occur under the [MISO] Tariff and the related Business Practice Manual."[74] The Michigan Commission argues that the split of Wisconsin Electric into two LBAs should be reversed because (1) the ReliabilityFirst[75] and NERC processes approving the new Wisconsin Electric LBA structure were procedurally defective, allowing no opportunity for affected customers to raise concerns about rate impacts; (2) NERC failed to address evidence of the cost impacts of the split; and (3) the requested split was not shown to be needed for reliability purposes.

47. As to the first claim, the Michigan Commission alleges that the NERC decision was procedurally defective because no notice was provided to the LSEs of the proposed split, and that the Michigan Commission and other affected parties had no opportunity to present evidence to ReliabilityFirst of the potential rate impacts resulting from the proposed LBA split. As to the second claim, the Michigan Commission states that it provided input to NERC about the cost implications of the split prior to NERC's approval, but that NERC ultimately determined that it had "no authority to address the cost allocation issues raised in response to the proposal to form the Michigan Upper Peninsula LBA."[76] Finally, as to the third claim, that the split was not needed for reliability purposes, the Michigan Commission challenges the ostensible operational reasons Wisconsin Electric provided for establishing two separate LBAs, and argues that the LBA split was initiated for the sole purpose of achieving a re-allocation of costs from Wisconsin customers to Michigan customers. Moreover, the Michigan Commission

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[74] Michigan Commission's Complaint at 2.

[75] ReliabilityFirst is the Regional Entity for the Wisconsin Electric operating area (i.e., the entity with certain delegated enforcement authority from NERC), and therefore had the initial responsibility to review Wisconsin Electric's application to create two separate LBAs.

[76] *Id.* at 13.

asserts that Wisconsin Electric admitted that the creation of the new metering boundary at the Michigan border "will not itself directly improve the physical reliability challenges" of that region.[77]

48. The Michigan Commission thus argues that the Commission should set aside NERC's certification of separate LBAs within Wisconsin Electric due to a lack of demonstrable reliability benefits. In the alternative, the Michigan Commission asks the Commission to clarify that any such split will not affect the way SSR costs are allocated, arguing that such a clarification is necessary to "negate the incentive for an LSE to manipulate the allocation of costs by changing [LBA] boundaries."[78]

B. Notice and Responsive Pleadings

49. Notice of the Michigan Commission's Complaint was published in the *Federal Register*, 79 Fed. Reg. 58,765 (Sept. 30, 2014), with interventions and protests due on or before October 9, 2014. Both NERC and Wisconsin Electric submitted timely answers to the Michigan Commission's Complaint.

50. Timely motions to intervene were filed by: Wolverine, ATC, the Mines, MPPA, WPS, Exelon Corporation, Consumers, METC, WPPI Energy, WP&L, Cloverland, DTE, Verso Paper, Integrys, and Mackinac. A notice of intervention was filed by the Wisconsin Commission. On December 4, 2014, UPPCo filed a motion to intervene out-of-time.

51. Substantive comments or protests were filed by: Verso Paper, Integrys, the Wisconsin Commission, the Mines, and a number of individual commenters, largely comprised of Wisconsin Electric retail ratepayers within the Upper Peninsula. In addition, comments were filed out of time by the Michigan Representatives, Michigan State Senator Carol M. Viventi, and John C. Procario.

52. Motions for leave to answer and answers to the comments, protests, and answers of other parties were filed by Integrys, MISO, Verso Paper, Wisconsin Electric and the Michigan Commission.

1. Answers to Michigan Commission's Complaint

53. In its answer to the Michigan Commission's Complaint, NERC maintains that the complaint fails to meet the minimum requirements of Rule 206 of the Commission's

[77] *Id.* at 14.

[78] *Id.* at 16.

Rules of Practice and Procedure because it does not "clearly identify the action or inaction which is alleged to violate applicable statutory or regulatory requirements." NERC explains that its certification of the Michigan Upper Peninsula LBA was not procedurally defective, as NERC adhered to its Commission-approved internal Rules of Procedure by ensuring that the Michigan Upper Peninsula LBA "has the tools, processes, training and procedures" in place to allow it to meet all requirements applicable to an LBA.[79] NERC also maintains that its actions in certifying the Michigan Upper Peninsula LBA do not constitute "approval" of Wisconsin Electric's proposal for purposes of cost allocation. Finally, NERC notes that it was not required under its Rules of Procedure to find that creation of the Michigan Upper Peninsula LBA was necessary in order to remedy physical reliability concerns, but merely to ensure that the proposed new LBA does not create reliability issues.

54. NERC also disagrees with the Michigan Commission's contention that NERC is not required to entertain comments or evidence from stakeholders. NERC states that its evaluation is limited to a technical evaluation of the entity's operational capabilities and ability to meet NERC's Reliability Standards, which it has done.[80] NERC states that it confirmed Wisconsin Electric's competency to operate the Michigan Upper Peninsula LBA reliably and issued its certification report on August 28, 2014.

55. In its answer to the Michigan Commission's Complaint, Wisconsin Electric also argues that the complaint should be denied because NERC's certification of the Michigan Upper Peninsula LBA did not violate any NERC rule or any portion of FPA section 215.[81] In addition, Wisconsin Electric argues that the complaint should be dismissed because "there already are existing proceedings at the Commission where all of the relief requested by [the Michigan Commission] (regarding SSR Unit cost impacts and cost allocation issues) is being addressed."[82] Notably, Wisconsin Electric states that it opposes the use of the Michigan Upper Peninsula LBA to allocate the costs of the Presque Isle SSR units, and instead advocates for use of commercial nodes in allocating such costs. Wisconsin Electric explains that the MISO Tariff does not require use of LBA boundaries in assigning SSR costs, and asserts that any change in LBA boundaries should not result in a change in assignment of costs. Finally, Wisconsin Electric maintains that the Michigan Commission failed to provide any substantive basis for

[79] NERC Answer at 2-3.

[80] *Id.* at 5-6.

[81] Wisconsin Electric Answer to Michigan Commission's Complaint at 3.

[82] *Id.*

overturning the NERC decision, and points out several operational benefits from the creation of the Michigan Upper Peninsula LBA.

56. Wisconsin Electric states that the Michigan Commission's Complaint should be denied for failure to provide adequate support for its claims regarding the substance of NERC's decision. Wisconsin Electric states that NERC has no authority to address cost allocation issues, as acknowledged by the Michigan Commission.[83]

57. Finally, Wisconsin Electric asserts that the Michigan Commission's Complaint should be denied due to failure to state a claim for which relief can be granted. Specifically, Wisconsin Electric states that the only entities that can be respondents in NERC proceedings under the NERC Rules and Procedures are Respondents, which the Michigan Commission is not because it is not a registered entity.[84] As such, Wisconsin Electric argues that the Michigan Commission lacks the standing to appeal a certification.

2. Comments, Protests and Subsequent Answers

58. The timely comments submitted by Verso Paper and Integrys in Docket No. EL14-103-000, as well as a number of the subsequent answers submitted in that docket, discussed above, were also filed in response to the Michigan Commission's Complaint.

59. In addition, the Mines filed limited substantive comments in support of the Michigan Commission's Complaint, expressly requesting consolidation of the two complaint proceedings. The Mines, noting the overlap between the two complaints, urge the Commission to consolidate their complaint with the Michigan Commission's Complaint in the interest of efficiency.[85] The Mines also urge the Commission to expeditiously set the matter for hearing, grant the relief requested from the Commission, and prohibit implementation of the split of the WEC LBA and formation of the Michigan Upper Peninsula LBA without prior Commission approval.

60. On October 24, 2014, Wisconsin Electric filed an answer in response to the Mines' request for consolidation. Wisconsin Electric asserts that administrative efficiency would not be enhanced by such consolidation because the complaints are by two different parties and are against two different entities. Additionally, Wisconsin

[83] *Id.* at 9-10 (citing Michigan Commission's Complaint Exhibit MI-2 at P 21).

[84] *Id.* at 12-13 (citing NERC Rules of Procedure, Appendix 4C, Attachment 2 – Hearing Procedures, Section 1.1.5 – Definitions ("respondent")).

[85] Mines Comments at 3-4.

Electric contends that the two complaints concern different and unrelated regulatory functions, namely NERC's certification of the Michigan Upper Peninsula LBA and cost allocation under the MISO Tariff. Wisconsin Electric also argues against setting the Complaints for hearing procedures. It states that the Mines have not identified material issues of fact in dispute that would merit a hearing proceeding, only mentioning that they are interrelated.[86]

IV. Discussion

A. Procedural Matters

61. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2014), the notices of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to the proceedings in which they were filed. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2014), we grant UPPCo's late-filed motion to intervene in each of the above-captioned dockets given its interest in the proceedings, the early stage of the proceedings, and the absence of undue prejudice or delay.

62. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2014), prohibits an answer to a protest or answer unless otherwise ordered by the decisional authority. We accept the answers filed in these proceedings because they have provided information that assisted us in our decision-making process.

B. Commission Determination

63. The Mines' Initial and Amended Complaints and the Michigan Commission's Complaint are concerned with MISO's use of an LBA-based cost allocation methodology for allocating the costs associated with the Presque Isle SSR Unit. As noted above, in the Rehearing Order issued concurrently with the instant order, we find that the cost allocation proposed by MISO for the Presque Isle SSR Unit, which uses the optimization-LBA approach in MISO's Business Practice Manual (BPM), is not just and reasonable, as it is inconsistent with section 38.2.7.k of MISO's Tariff, which requires MISO to allocate SSR costs to "the LSE(s) which require(s) the operation of the SSR Unit for reliability purposes." In the Rehearing Order, we require MISO to propose in a compliance filing a new study methodology that identifies the LSEs that require the Presque Isle SSR Unit for reliability purposes, along with a revised rate schedule that adjusts the allocation of SSR costs accordingly.[87] As such, this revised rate schedule will no longer be LBA-

[86] Wisconsin Electric October 24 Answer at 4-5.

[87] Rehearing Order, 150 FERC ¶ 61,104 at PP 2, 80-89.

based. Further, in that order, we reject the LBA-based rate schedule filed in Docket No. ER14-2952-000 that both the Mines and the Michigan Commission find objectionable.[88] Accordingly, we dismiss the complaints as moot.

64. Given this, we do not reach the arguments put forth in the complaints that it is necessary for the Commission to approve the split of the WEC LBA and the creation of the Michigan Upper Peninsula LBA because of the effect of the split on jurisdictional rates, because we make clear in the Rehearing Order that the allocation of Presque Isle SSR costs will not depend on LBA boundaries.[89]

65. However, we do find it appropriate to address certain arguments raised in the complaints and answers, given the challenges both to NERC's processes and parties' ability to bring complaints at the Commission. First, we reject the arguments of the Mines and the Michigan Commission that NERC lacks jurisdiction to certify the Michigan Upper Peninsula LBA or that its certification process was deficient, and therefore find no basis for overturning NERC's certification of the new Michigan Upper Peninsula LBA. We agree with NERC that its certification process is governed by Commission-approved Rules of Procedure, and that under those rules NERC was obligated to assess whether the new Michigan Upper Peninsula LBA has the technical capability to ensure compliance with all applicable Reliability Standards.[90] NERC was

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[88] In fact, the Rehearing Order rejects MISO's filing, made in Docket No. ER14-2952-000, to reflect the impact on SSR cost allocation of Wisconsin Electric's split into the WEC LBA and the Michigan Upper Peninsula LBA. *See id.* PP 2, 100.

[89] In the Rehearing Order, we make no findings as to the whether the LBA-based BPM cost allocation methodology might produce just and reasonable cost allocations for SSR Units other than the SSR Units at issue in that order. As such, in the Rehearing Order, we find that if MISO proposes to apply its BPM methodology in future filings, MISO must address the concerns with the methodology that are identified in the Rehearing Order and show that the methodology allocates SSR costs to those LSEs that require the operation of the SSR Unit for reliability purposes, such that assignment of costs is commensurate with the benefits received by such LSEs. Rehearing Order, 150 FERC ¶ 61,104 at P 86, n.211. Accordingly, we decline to address any general concerns raised in the Mines' Initial and Amended Complaints and the Michigan Commission's Complaint with regard to the justness and reasonableness of the impact of the split of the WEC LBA on other SSRs, and the application of MISO's LBA-based BPM cost allocation for other SSRs, as speculative.

[90] *See* NERC Answer at 6-7 (citing to, inter alia, NERC Rule of Procedure § 500 (governing NERC's registration and certification process for [LBAs]), and § 501

(continued…)

neither required to find that creation of the new Michigan Upper Peninsula LBA would enhance reliability, nor to consider its potential economic implications. Our findings with respect to the adequacy of NERC's certification decision and review process should not be taken to suggest that we have no authority or obligation to review and approve any change in cost allocation or tariff rates that could occur as a result of a change in LBA status. However, in this situation, given our concurrent decision on the apportionment of SSR costs for the Presque Isle, Escanaba and White Pine SSR units, we find that NERC's certification of the new Michigan Upper Peninsula LBA will not have an impact on SSR cost allocation or otherwise affect rates as the complainants allege.

66. As for the arguments put forth in the Mines' Amended Complaint that state regulatory approvals are needed to terminate operations at the Presque Isle plant, that an SSR agreement may not be necessary, and that there is no economic justification for Wisconsin Electric to terminate operations at the Presque Isle plant, we find that we have answered each of these issues in other proceedings. As we state in the Rehearing Order, the Commission addressed these issues in the November 10 Order.[91] With respect to arguments that some or all of the Presque Isle Units 5-9 should not qualify for SSR treatment, the Commission found in the November 10 Order that MISO properly followed the SSR study and review process in accordance with the Tariff and adequately demonstrated that all five Presque Isle units are needed for reliability during the term of the SSR agreement that was accepted in the November 10 Order.[92] With regard to arguments that Wisconsin Electric did not receive the necessary state regulatory approvals to retire Presque Isle Units 5-9, the Commission found in the November 10 Order that if there are state laws that prevent the retirement, the enforcement of those laws is beyond the scope of the SSR proceeding.[93] With respect to Integrys's arguments that Wisconsin Electric already recovers costs for the Presque Isle units in its retail rate base, Wisconsin Electric's retail rates are not before us here, as such retail rates fall within the relevant state commissions' jurisdiction and not within this Commission's jurisdiction.[94] Furthermore, we find that retail rate treatment is not relevant to setting the

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("requiring any utility seeking registration to provide proper documentation demonstrating its ability to satisfactorily function as [an LBA]")).

[91] Rehearing Order, 150 FERC ¶ 61,104 at P 99.

[92] November 10 Order, 149 FERC ¶ 61,114 at P 36.

[93] *Id.* P 38.

[94] *See Southwest Power Pool, Inc.*, 119 FERC ¶ 61,199 (2007).

just and reasonable level of compensation for Commission-jurisdictional service provided by an SSR Unit under the MISO Tariff.[95]

67. Last, we reject Wisconsin Electric's assertion that the Michigan Commission has failed to state a claim for which relief can be granted. Wisconsin Electric's argument is based on the assertion that the Michigan Commission cannot be a "respondent" under NERC's Rules of Procedure because a "respondent" is defined solely as a Registered Entity in Appendix 4C of the NERC Rules of Procedure and because it claims only "Respondents have standing to appeal a NERC ruling certifying new [LBAs]."[96] However, Wisconsin Electric's reliance on a definition used in Attachment 2 of Appendix 4C of the NERC Rules of Procedure, which governs hearing procedures as part of NERC's Compliance Monitoring and Enforcement program, is misplaced. These procedures relate to hearings on compliance and enforcement matters *at the NERC or Regional Entity level*, and not to appeals to the Commission of NERC certification decisions. To the extent NERC's Rules of Procedure address review of certification decisions, the relevant procedures are set out in Appendix 5A, Section VI, and provide that *any entity* may appeal an organization certification decision by a Regional Entity:

> **Organization Certification Appeals Procedure**
>
> 1. Appeal for an Organization Certification Finding.
>
> Any entity can appeal an organization Certification decision issued as a result of the Certification process.[97]

Moreover, with respect to the right to appeal a final NERC certification decision *to the Commission*, NERC's Rules of Procedure do not set out any restrictions as to the entities that can seek relief, and instead explicitly state that "[p]arties retain the right to seek further review of a decision in whatever regulatory agency or court that may have jurisdiction."[98] Therefore we reject Wisconsin Electric's arguments on this issue.

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[95] Rehearing Order, 150 FERC ¶ 61,104 at P 75.

[96] *See* Wisconsin Electric Answer to Michigan Commission's Complaint at 12 (citing to NERC Rules of Procedure 4C, Attachment 2 – Hearing Procedures, Section 1.1.5 – Definitions ("respondent")).

[97] NERC Rules of Procedure, Appendix 5A, Section VI.1 and Fig. 4.

[98] *Id.* at Section VI.2.d.

The Commission orders:

The Mines' Initial and Amended Complaints and the Michigan Commission's Complaint are hereby dismissed, as discussed in the body of this order.

By the Commission. Commissioner Honorable is not participating.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

150 FERC ¶ 61,213
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Cheryl A. LaFleur, Chairman;
Philip D. Moeller, Tony Clark,
Norman C. Bay, and Colette D. Honorable.

North American Electric Reliability Corporation Docket No. RR15-4-000

ORDER ON ELECTRIC RELIABILITY ORGANIZATION RISK BASED REGISTRATION INITIATIVE AND REQUIRING COMPLIANCE FILING

(Issued March 19, 2015)

1. On December 11, 2014, the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), submitted a petition for approval of proposed revisions to the NERC Rules of Procedure that would implement NERC's Risk-Based Registration (RBR) initiative. According to NERC, the initiative is intended to ensure that entities are subject to an appropriate set of applicable Reliability Standards by using a consistent approach to risk assessment and registration. Major reforms to the registration process proposed by NERC include the elimination of the purchasing-selling entity, interchange authority, and load-serving entity functional registration categories; modifications to the thresholds for registering entities as distribution providers; and procedural improvements to the registration process. NERC states that the ERO compliance program and stakeholders will benefit from the proposed revisions as they appropriately focus resources on entities with the greater potential impact on reliability.

2. As discussed below, pursuant to section 215(f) of the Federal Power Act (FPA),[1] the Commission approves in part, and denies in part, NERC's RBR petition. The Commission finds reasonable NERC's overall goal of ensuring entities are registered and made subject to the Reliability Standards based on the risk they pose to reliability. Many of the proposed revisions clearly promote this goal and are adequately justified. However, as discussed below, the Commission finds that NERC has not adequately justified the proposed elimination of the load-serving entity function from the registry process. Accordingly, the Commission denies, without prejudice, this aspect of the

[1] 16 U.S.C. § 824o(f) (2012).

NERC proposal and directs NERC to submit a compliance filing within 60 days of the date of the issuance of this order to address the Commission's concerns regarding the proposed elimination of the load-serving entity function. In addition, while the Commission approves NERC's proposed revisions related to the registration of distribution providers, we direct that NERC must include Reliability Standard PRC-005 (Transmission and Generation Protection System Maintenance and Testing) as applicable to underfrequency load shedding-only distribution providers, as discussed herein. The Commission also directs one further modification to NERC's proposed revisions to the Rules of Procedure, and directs NERC to submit a one-year compliance filing discussing the implementation of the RBR program.

I. Background

A. Regulatory Background

3. Section 215(f) of the FPA provides that the "Electric Reliability Organization shall file with the Commission for approval any proposed rule or proposed rule change, accompanied by an explanation of its basis and purpose," and that the proposed rule or rule change "shall take effect upon a finding by the Commission, after notice and opportunity for comment, that the change is just, reasonable, and not unduly discriminatory or preferential, and is in the public interest and satisfies the requirements of [FPA section 215] (c)."[2] Section 39.10(a) of the Commission's regulations provides that the ERO must file for Commission approval any proposed ERO rule or rule change.[3]

4. On July 20, 2006, the Commission issued an order certifying NERC as the ERO under section 215 of the Federal Power Act (FPA).[4] In that order, the Commission, among other things, generally accepted a comprehensive set of documents defining the structure, governance, and operational procedures of the ERO, including the Rules of Procedure, which includes the NERC registration process.[5]

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[2] *Id.*

[3] 18 C.F.R. § 39.10(a) (2014).

[4] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062 (2006) (*Certification Order*), *order on compliance*, 118 FERC ¶ 61,030, *order on compliance*, 118 FERC ¶ 61,190, *order on reh'g*, 119 FERC ¶ 61,046 (2007), *rev. denied sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[5] *See* NERC Rules of Procedure, Section 500 (Organization Registration and Certification), App. 5A (Organization Registration and Organization Certification Manual), and App. 5B (Statement of Compliance Registry Criteria).

B. NERC Registration Process

5. The starting point for monitoring and enforcing compliance with Commission-approved Reliability Standards is NERC's processes for identifying and registering owners, operators, and users of the Bulk-Power System that are responsible for performing reliability-related functions in accordance with the approved Reliability Standards.

6. NERC's Statement of Compliance Registry Criteria (Registry Criteria) articulates a three-step process for determining whether Bulk-Power System users, owners and operators must be registered in one or more functional categories for compliance with mandatory Reliability Standards. Section I provides that an entity that uses, owns or operates elements of the bulk electric system pursuant to NERC's definition is a candidate for registration. Section II of the Registry Criteria categorizes registration candidates under fifteen functional entity categories. Section III provides threshold criteria for excluding entities identified as candidates for registration under Sections I and II. NERC and the Regional Entities identify candidate entities, which are then registered and included on the NERC Compliance Registry.[6] Organizations listed in the NERC Compliance Registry are responsible for knowing the contents of, and complying with, Reliability Standards applicable to their reliability functions.

II. NERC Petition: Risk-Based Registration Initiative

7. On December 11, 2014, NERC submitted a petition requesting the Commission's approval of its proposed revisions to the NERC Rules of Procedure to implement the RBR initiative. According to NERC, this initiative will ensure that "the right entities are subject to the right set of applicable Reliability Standards by using a consistent approach to risk assessment and registration."[7] NERC explains that it is transforming its approaches to compliance and enforcement to be forward-looking with a focus on high reliability risk areas. NERC states that, with a shift toward risk-based approaches, NERC is introducing "quantitative measures of reliability performance and the proposed revisions are a result of NERC's commitment to taking a risk-based approach to reliability and to incorporating lessons-learned through continuously improving and

[6] *See* NERC Rules of Procedure, section 501, which describes the scope of the registration program and explains that the Compliance Registry "shall set forth the identity and functions performed for each organization responsible for meeting Requirements …. of Reliability Standards."

[7] NERC Petition at 2.

adapting operations."[8] NERC states that the revised definition of "bulk electric system" has served as a model for the RBR initiative and is the basis for several proposed revisions. NERC explains that the proposed revisions are also consistent with the underlying goal of the definition of "bulk electric system," which is to provide transparency and consistency in the identification of elements and facilities that make up the bulk electric system.[9]

8. Specifically, NERC proposes the following reforms:

> 1. Modifications to the Registry Criteria, including (a) the removal of purchasing-selling entities, interchange authorities, and load-serving entities as functional registration categories, (b) modifications to the threshold for registering entities as distribution providers, and (c) alignment of five functional registration categories to the definition of bulk electric system;
>
> 2. The risk-based application of sub-set lists of Reliability Standards (including underfrequency load shedding-only distribution providers);
>
> 3. Procedural revisions to the registration process; and
>
> 4. Revisions to the Rules of Procedure to implement the risk-based registration initiative.

Regarding the proposed elimination of the purchasing-selling entity, interchange authority, and load-serving entity categories, NERC explains that the activities of these types of entities are commercial in nature, and their removal from the Compliance Registry poses little, if any, risk to the reliability of the Bulk-Power System. In particular, NERC notes that these three categories of entities do not own or operate bulk electric system equipment.[10] Further, NERC explains that "[h]istorical enforcement data

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[8] *Id*. at 3.

[9] *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, Order No. 773, 141 FERC ¶ 61,236 (2012); *order on reh'g*, Order No. 773-A, 143 FERC ¶ 61,053 (2013), *order on reh'g and clarification*, 144 FERC ¶ 61,174 (2013), *appeal pending sub nom. People of the State of New York and the Pub. Serv. Comm'n of New York v. FERC,* No. 13-2316 (2d. Cir. filed June 12, 2013).

[10] *See* NERC Petition at 20-32 (providing rationale for the proposed elimination of the purchasing-selling entity, interchange authority, and load-serving entity categories).

(continued ...)

has confirmed that these entities have not caused or exacerbated events or system disturbances that jeopardized reliability of the grid, and nearly all violations posed a minimal actual risk to reliability and the vast majority posed a minimal potential risk."[11]

9. NERC also proposes revisions to five other functional registration categories - transmission owners, transmission operators, generator owners, generator operators, and distribution providers - to align with the definition of bulk electric system. In addition, NERC proposes to revise the Registry Criteria for distribution providers by increasing the MW registry threshold from 25 MW to 75 MW. According to NERC, the 75 MW threshold aligns with the 75 MVA threshold for certain generating resources as set forth in the definition of bulk electric system.

10. Further, NERC proposes changes to the Rules of Procedure that explicitly allow NERC to establish a sub-set list of Reliability Standards applicable to particular entities, as warranted. NERC explains that this provision is then applied to certain distribution providers that do not meet any other distribution provider registration criteria, but own, control, or operate underfrequency load shedding protection systems designed for the protection of the bulk electric system.[12]

11. NERC sums up the impacts of the proposed registration changes as follows:

> Fundamentally, the proposed revisions … will reduce the regulatory burden of approximately 700 organizations, and allow such organizations to focus on issues that impact reliability. Of the 1,603 unique organizations listed on the NERC Compliance Registry, registered for 4,311 reliability functions, only about 700 organizations are expected to be impacted by the proposed deactivations and deregistration. Approximately 200 organizations would be deregistered from the NERC Compliance Registry and approximately 500 organizations would be impacted by the proposed deactivations. For example, as a result of the proposed changes, approximately 14 organizations now on the NERC Compliance Registry as Load-Serving Entities are expected to be deregistered, 197 organizations now on the NERC Compliance Registry as Purchasing-Selling Entities are expected to

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In addition, NERC's Petition includes a Technical Report: Risk-Based Registration: Technical and Risk Considerations, that provides additional technical justification for the proposed registry modifications. *See id*. Exh. C.

[11] NERC Petition at 4.

[12] *Id*. at 5, 40.

be deregistered and no organizations now on the NERC Compliance Registry as Interchange Authorities would be deregistered.[13]

NERC also proposes the following procedural changes to its registration process: (1) the establishment of a materiality test for registration, which delineates the procedures and criteria for evaluating whether an entity has a material impact on reliability; and (2) a process to review registration, deactivation and deregistration decisions, as well as requests for sub-set lists of Reliability Standards. According to NERC, collectively, these proposed procedural improvements provide additional clarity and transparency to the registration requirements, roles, and responsibilities. To implement the proposed risk-based registration initiative, NERC proposes revisions to the following sections of the NERC Rules of Procedure - Section 302: Essential Attributes for Technically Excellent Reliability Standards; Section 501: Scope of the Organization Registration and Organization Certification Programs; Appendix 2: Definitions Used in the Rules of Procedure; Appendix 3D: Registered Ballot Body Criteria; Appendix 5A: Organization Registration and Certification Manual; and Appendix 5B: Statement of Compliance Registry Criteria. Finally, NERC states that it will submit an informational filing within one year of Commission action "to ensure that there are no unintended consequences to reliability" as a result of the RBR proposal.

III. Notice of Filing and Responsive Pleadings

12. Notice of NERC's filing was published in the *Federal Register*, 79 Fed. Reg. 77,467 (2014) with interventions and protests due on or before January 12, 2015. Edison Electric Institute, Snohomish County Public Utility District No. 1, and Wisconsin Electric Power Company filed timely motions to intervene. The California Municipal Utilities Association (CMUA), Canadian Electricity Association (CEA), Electric Power Supply Association (EPSA), and Golden Spread Electric Cooperative, Inc. (Golden Spread) filed motions to intervene and comments. American Public Power Association, National Rural Electric Cooperative Association and Transmission Access Policy Study Group (collectively, Trade Associations) jointly filed a motion to intervene and comments. The PSEG Companies[14] and the Electricity Consumers Resource Council (ELCON) filed

[13] *Id*. at 6 (footnote omitted). NERC explains that the term "deactivation" refers to removal of an entity from the NERC Compliance Registry for a specific functional category. If all functional categories have been deactivated for a given entity, such entity would be "deregistered" and removed from the NERC Compliance Registry. *Id*. at 18.

[14] The PSEG Companies are: Public Service Electric and Gas Company, PSEG Power LLC, and PSEG Energy Resources & Trade LLC.

comments. The Cogeneration Association of California and the Energy Producers and Users Coalition (QF Parties) also filed a motion to intervene and protest.

13. Commenters, including Trade Associations, ELCON, EPSA, Golden Spread, CEA and CMUA, support NERC's proposal. Commenters see NERC's filing as an important step toward a more risk-informed approach that promotes focus on high reliability risk areas and fair treatment of entities. Commenters also contend that the proposed removal and modification of functions are technically justified. Trade Associations support the proposal as it aligns registration with the bulk electric system definition, achieves the right registration outcomes, and avoids unnecessary confusion. Golden Spread supports the Trade Associations' comments. ELCON states that the RBR initiative will yield numerous benefits including the ability of NERC to exercise discretion to exclude entities that are not material to reliability. While PSEG Companies and QF Parties comment that they support the goals of the RBR proposal, they also raise implementation concerns and request certain additional revisions to NERC's proposal.

14. On January 26, 2015, NERC filed a motion for leave to answer and an answer to the comments of PSEG Companies. Trade Associations filed a joint response to PSEG Companies and QF Parties.

IV. Discussion

A. Procedural Matters

15. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure,[15] the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2014), prohibits an answer to a protest or an answer unless otherwise ordered by the decisional authority. The Commission may waive this rule when the answer provides information that assists the Commission in its decision-making process. We accept NERC's and Trade Associations' comments because they assisted in our decision-making process.

B. Commission Determination

16. Pursuant to section 215(f) of the FPA, we approve in part, and deny in part, NERC's RBR petition. In general, we believe that NERC's alignment of the registration process with the risks to the interconnected transmission network posed by different types

[15] 18 C.F.R. § 385.214 (2014).

of entities is an improvement. We agree with NERC's overall goal of ensuring that entities are registered and made subject to the Reliability Standards based on risk entities pose to the bulk electric system. We find that NERC and stakeholders will benefit from the proposed revisions as efforts will appropriately be directed towards activities with a greater potential impact on bulk electric system reliability. These benefits translate into time and resources saved, which help ensure that the costs of reliability are proportionate to the benefits. We also agree with NERC that it is important to achieve reliability risk mitigation while ensuring the reliability and security of the interconnected transmission network, and the RBR initiative is consistent with this pursuit.

17. Therefore, we approve the following changes to the Rules of Procedure to implement RBR, as described in NERC's filing, as just, reasonable, not unduly discriminatory and in the public interest and that also satisfy the requirements of FPA section 215(c): (1) modifications to the functional entity categories, including (a) the removal of purchasing-selling entities and interchange authorities as functional registration categories, and (b) modifications to the threshold for registering entities as distribution providers; (2) the risk-based application of sub-set lists of Reliability Standards to underfrequency load shedding-only distribution providers); (3) the procedural revisions to the registration process; and (4) the proposed revisions to the Rules of Procedure, and directing one further Rule modification, discussed below.

18. However, as discussed below, the Commission finds that NERC has not provided adequate justification for eliminating the load-serving entity function. Accordingly, we deny, without prejudice, this aspect of NERCs proposal, and we direct NERC to submit a compliance filing within 60 days that addresses our concerns with the load-serving entity proposal, discussed below. In addition, while we approve the risk-based application of sub-set lists of Reliability Standards (including underfrequency load shedding-only distribution providers), we direct NERC to include Reliability Standard PRC-005 as applicable to those entities.

19. Further, consistent with NERC's commitment, we direct NERC to submit a compliance filing twelve months from the date of issuance of this order that discusses RBR implementation.[16] In addition to addressing potential "unintended consequences to reliability as a result of the instant proposal," NERC should also address: (1) the benefits achieved by RBR implementation; (2) any specific costs associated with ERO and Regional Entity implementation of the program; (3) information and statistics regarding review panel decisions, including but not limited to the types of functional entities seeking application of sub-set lists and Reliability Standards most frequently removed

[16] *See* NERC Petition at 8, 56.

from compliance by sub-set lists; and (4) any other relevant information that would assist the Commission in understanding RBR implementation.

20. Below the Commission discusses: (1) elimination of purchasing-selling entity and interchange authority functional categories; (2) revision of the distribution provider threshold for registration; (3) elimination of the load serving entity function; (4) underfrequency load shedding-only distribution providers; and (5) procedural changes to the registration process.

1. Elimination of Purchasing-Selling Entity and Interchange Authority Functional Categories

NERC Proposal

21. NERC currently registers purchasing-selling entities, defined by NERC as "[t]he entity that purchases, or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-selling entities may be affiliated or unaffiliated merchants and may or may not own generating Facilities."[17] NERC proposes to eliminate the purchasing-selling entity function from the Compliance Registry. According to NERC's analysis, eliminating the purchasing-selling entity function would have little to no effect on reliability.[18] NERC regards the purchasing-selling entity function as market-driven rather than a reliability-driven function.

22. NERC defines an interchange authority as "[t]he responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes."[19] NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system.[20] Further, NERC states that no entities will be deregistered under this

[17] NERC Registry Criteria at 6.

[18] *See* NERC Petition at 20-24 (discussing impact on reliability from eliminating purchasing-selling entity category).

[19] NERC Registry Criteria at 6.

[20] *See* NERC Petition at 25-28 (discussing impact on reliability from eliminating interchange authority category).

proposal given that all currently registered interchange authorities are also registered as either a balancing authority or reliability coordinator.

Comments

23. Commenters support removal of the purchasing-selling entity function and the interchange authority function. Trade Associations, EPSA, CMUA and CEA support removal of the purchasing-selling entity function because its commercial contracting function does not impact reliability requirements. PSEG Companies comments that, while it "may ultimately agree" to deactivating these functions, PSEG Companies believes that "deactivat[ing] functions and then changing impacted Reliability Standards is the wrong sequence."[21] PSEG Companies maintains that revisions should first be vetted with stakeholders through the reliability standards development process and that, once a function is removed from applicability to all standards, the function can be removed from the Compliance Registry. PSEG Companies states that this approach would allow better coordination with the North American Energy Standards Board (NAESB) on commercial matters, noting that NAESB commercial standards "often tie their applicability directly to the functions utilized by the NERC Reliability Standards."[22]

Answers

24. In response to PSEG Companies, NERC explains that "only those entities that are registered for a given function and included in the NERC Compliance Registry are responsible for, and may be held accountable to, the requirements of a Reliability Standard. Therefore, as a result of the deactivation of … registration functions, any Reliability Standard that identifies the deleted functions as applicable entities will be moot as to those entities."[23] NERC further explains that, after Commission approval of the deactivation, any necessary changes to the NERC Glossary of Terms Used in Reliability Standards (NERC Glossary) and corresponding Reliability Standards will be considered through the standard development process. NERC notes that it has initiated a project to align NERC Glossary terms with definitions used in the Rules of Procedure. Trade Associations add that PSEG Companies' proposed approach would create "needless hurdles" to implement the registration reforms, which NERC appropriately addresses through changes to NERC Rules including the Registry Criteria.

[21] PSEG Companies Comment at 4. PSEG Companies indicates that this concern applies to the elimination of the load-serving entity function as well.

[22] *Id*. at 6.

[23] NERC Answer at 6.

Commission Determination

25. We approve NERC's proposed removal of the purchasing-selling entity function. We agree with NERC that the purchasing-selling entity function is primarily market-driven and has minimal reliability impacts. Thus, we are persuaded by NERC's analysis of reliability impact that eliminating the purchasing-selling entity function would have "little to no effect" on the reliability of the Bulk-Power System.[24]

26. For similar reasons, we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules.[25] We are further persuaded by NERC's explanation that no entities now registered as interchange authorities will be deregistered given that all currently registered interchange authorities are also registered as either a balancing authority or reliability coordinator, and will remain subject to the applicable Reliability Standards.

27. We disagree with the PSEG Companies' argument that a modification to the registration functions must first go through the standard development process to be considered for deactivation. As explained by NERC and Trade Associations, the registration process is developed and maintained pursuant to the NERC Rules of Procedure. NERC's petition pertains to proposed revisions to the NERC Rules, such as the Registry Criteria. NERC has provided opportunity for stakeholder input when drafting the proposed RBR revisions, consistent with procedures for NERC Rule changes.[26] We understand that the RBR changes will *de facto* result in Reliability Standards that currently apply to purchasing-selling entities and interchange authorities applying to a "null set" of these entities. However, we find no procedural error or harm to bulk electric system reliability by NERC's chosen approach, provided that NERC adequately justifies the proposed elimination of the functional categories in the immediate proceeding. We do agree that NERC must coordinate with NAESB to ensure a proper "hand off" of commercial-related provisions, and address this in more detail later in the order.

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[24] *Id*. at 20.

[25] *Id*. at 25-26.

[26] *See* NERC Petition at 7.

2. Revision of Distribution Provider Threshold

NERC Proposal

28. Currently, the Registry Criteria threshold for registering distribution providers is "distribution provider system serving > 25 MW of peak [l]oad that is directly connected to the Bulk-Power System." NERC proposes to raise the peak load threshold for distribution providers from 25 MW to 75 MW and to reflect that an entity's system also must be "directly connected to the BES [bulk electric system]." According to NERC, distribution providers serving below 75 MW will remain eligible for registration if they own or operate protection systems, such as under voltage load shedding, special protection systems, remedial action schemes, or other transmission protection systems. NERC states that it conducted a survey of planning coordinators to assess the impact of modifying the criteria for distribution providers and reliability coordinators conducted an analysis to determine the consequences of the proposed changes.[27] According to NERC, all survey respondents stated that no gaps in reliability would be created by raising the distribution provider threshold to 75 MW. Further, the thresholds provide for registration of an entity as a distribution provider – regardless of peak load - if the entity owns, controls or operates certain facilities that are part of a protection system program (such as under voltage load shedding and remedial action schemes) designed for protection of the bulk electric system.[28]

Comments

29. Commenters, including Trade Associations, CMUA and ELCON support NERC's proposal to increase the threshold for entities that must register as distribution providers to 75 MW of peak load served. Trade Associations assert that the proposed revisions to the registration thresholds are reasonable and will not result in any material risk to reliability. Trade Associations add that except in very unusual cases, it is not necessary, from a risk-based perspective, to impose requirements on entities with peak loads below 75 MW. Further, Trade Associations agree with the analysis provided in NERC's Technical Report, which shows that distribution providers with peak loads under 75 MW serve a very small proportion of U.S. load.[29] Trade Associations provide their own

[27] *See* NERC Petition at 36, Exh. C (Technical Report) at 13-19 and 22.

[28] *See* NERC Petition, Exh. A (proposed NERC Rules of Procedure), Registry Criteria, section III.a.2. Likewise, distribution providers responsible for providing services related to Nuclear Plant Interface Requirements remain subject to registration.

[29] Trade Associations Comments at 5-6, and 12.

analysis, which they explain indicates that "increasing the threshold ... could remove more than 100 entities from full [distribution provider] registration (amounting to some 25% of the registered [distribution providers], while removing only 0.7% of the load served by NERC-registered [distribution providers]."[30] CMUA also supports the NERC proposal, asserting that the proposed 75 MW peak load threshold for distribution providers is conservative and the system could tolerate a higher threshold without adverse impacts to reliability.

Commission Determination

30. We approve the proposed revisions to the distribution provider registration threshold. We are persuaded by NERC that increasing the Registry Criteria threshold for distribution providers from 25 to 75 MW peak load will not pose a significant risk to the reliability of the Bulk-Power System.[31] We find that NERC's selection of 75 MW peak load threshold for distribution providers as a first step in determining materiality, aligning with the 75 MVA threshold for certain generating resources in the bulk electric system definition, is reasonable. In addition, we are persuaded by the finding in NERC's Technical Report, as well as Trade Association comments, that including on the Compliance Registry distribution providers with peak loads under 75 MW that serve a very small proportion of load and have no other specific materiality to bulk electric system reliability may not be needed to accomplish the reliability objectives of the applicable Reliability Standards. Moreover, as discussed above, a distribution provider is subject to registration regardless of peak load if the entity owns, controls or operates certain facilities that are part of a protection system program (such as under voltage load shedding and remedial action schemes) designed for protection of the bulk electric system.

31. While there are potentially some situations in which it would be appropriate for bulk electric system reliability to register a distribution provider with a peak load in the 25 to 75 MW range, we expect that those cases will be addressed through NERC's "material impact" process.[32] NERC also has appropriate safeguards in place, notably a

[30] *Id*. at 5. Attachment A graphically illustrates the cumulative impact, as well as percentage of impacted summer peak load by NERC region.

[31] NERC recognizes, and we agree, that certain entities with a 25 to 75 peak load range may have a specific materiality to reliability. NERC's petition includes revisions to the Registry Criteria that set forth a "materiality test" to assess individual impacts. *See* NERC Petition at 45, and discussion *infra*.

[32] NERC Petition at 45-46; and discussed in this order, *infra*.

quality control step in the registration process to notify relevant entities to ensure deactivation of a distribution provider will not cause reliability gaps or issues.[33] For these reasons, we approve NERC's revisions to the Registry Criteria pertaining to registration thresholds for distribution providers.

3. Elimination of the Load-Serving Entity Function

NERC Proposal

32. The currently-effective Registry Criteria defines a load-serving entity as an entity that "[s]ecures energy and Transmission Service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers."[34] Load-serving entities, among other things, submit load profiles and characteristics, plans, and forecasts as needed to the balancing authorities, purchasing-selling entities, planning coordinator, resource planners, and transmission planners and provide generation commitments and dispatch schedules to the balancing authority.[35]

33. In its petition, NERC proposes to eliminate the load-serving entity function from the NERC compliance registry. NERC states that load-serving entities' role of securing energy and transmission service is primarily a commercial contracting function. NERC explains that the load-serving entities' responsibilities that impact reliability are duplicative of those performed by other reliability functions. For example, NERC observes that certain Reliability Standards, such as FAC-002-1, PRC-010-1 and PRC-022-1, apply to both load-serving entities and distribution providers. Likewise, distribution providers and transmission owners, which are subject to the current load-shedding Reliability Standards, typically carry out load shedding because load-serving entities do not typically own or operate any equipment.[36] NERC states that load-serving entities also are subject to requirements that are duplicative of the functions performed by

[33] *See* NERC Petition at 19.

[34] NERC Rules of Procedure, App. 5B (Registry Criteria) at 6.

[35] NERC Functional Model (Version 5) at 55. *See also* Reliability Standards MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-021-1, and MOD-031-1 (Demand and Energy Data) which will replace MOD-16 through 19 and 21 in 2016. *See Demand and Energy Data Reliability Standard*, Order No. 804, 80 Fed. Reg. 9596 (Feb. 24, 2015), 150 FERC ¶ 61,109 (2015).

[36] NERC Petition at 31.

resource planners and balancing authorities.[37] Moreover, according to NERC, while the load-serving entity's role is commercial, the Reliability Standards that apply to load-serving entities "relate almost exclusively to equipment and physical operations," indicating a "disconnect" between the requirements currently assigned to load-serving entities and their role of contracting to secure energy and transmission services.[38]

34. NERC also provides an analysis of the Reliability Standards that currently apply to load-serving entities. In particular, NERC identifies 31 Reliability Standards that currently apply to load-serving entities. According to NERC, several reliability standards under development would remove the load-serving entity as an applicable entity.[39] NERC anticipates that upon completion of these projects, only nine Reliability Standards would remain applicable to load-serving entities.[40] With regard to the nine remaining Reliability Standards, NERC states that other entities carry out activities assigned to load-serving entities.[41]

35. NERC explains that elimination of the load-serving entity function would result in "deactivating" 452 of the 466 currently-registered load-serving entities, i.e., these entities would remain on the Compliance Registry as responsible for other functions.[42] NERC provides an analysis, including a requirement-by-requirement mapping document, to demonstrate that load-serving entities that remain registered under other functional categories will continue to perform load-serving entity-related activities. Fourteen remaining load-serving entities would be "deregistered" because they are not registered for any other function. For these remaining entities, NERC indicates that load-serving entity functions will continue to be performed pursuant to tariffs, interconnection agreements, or similar provisions.[43]

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[37] *Id*. at 28.

[38] *Id*. at 31.

[39] *See* NERC Petition at 28-31.

[40] BAL-005-0.2b; FAC-002-1; INT-011-1; MOD-004-1; MOD-020-0; MOD-031-1; MOD-032-1, NUC-001-2.1; and TOP-002-2.1b.

[41] NERC Petition at 31 and Exh. C (Technical Report), App. A (LSE Mapping Document).

[42] *See* NERC Petition at 6, Exh. C (Technical Report) at App. C (Proposed Deactivations).

[43] NERC Petition at 31.

Comments

36. Trade Associations, ELCON and Golden Spread support NERC's removal of the load-serving entity function. Trade Associations add that NERC's Technical Report demonstrates, with respect to each standard and requirement applicable to load-serving entities, that no material risk to bulk electric system reliability results from the proposed elimination of load-serving entity as a function requiring registration and the deactivation of load-serving entities. Trade Associations highlight and provide additional context with respect to certain reliability standards affected by NERC's proposed elimination of the load-serving entity function.

Commission Determination

37. While NERC provides a considerable amount of information and analysis regarding the proposed elimination of the load-serving entity function, we nonetheless find that NERC's analysis is incomplete. As explained in more detail below, eliminating the load-serving entity function does not remove the need to provide information required for reliable operation of the bulk electric system.[44] Upon elimination of the load-serving entity as a registered function, it is unclear whether and how some entities will continue to provide information or who will assume their obligations. It appears that some of the load-serving entities will be required to continue to provide the information through their responsibilities as other registered functions. However, NERC has not adequately explained which entities will continue to provide this information. Because of the gaps in NERC's analysis, discussed below, we are unable to satisfactorily conclude on the current record in this proceeding that the elimination of the load-serving entity function will have no material impact on the reliability of the Bulk-Power System. Accordingly, we deny, without prejudice the proposed elimination of the load-serving entity function, and we direct NERC to submit a compliance filing within 60 days of the date of issuance of this order to address our concerns, discussed below.

38. We are concerned that NERC has not adequately explained how certain load-serving entity reliability tasks will be performed going forward. According to NERC, of the 466 currently registered load-serving entities, 452 entities would be deactivated as load-serving entities but remain registered as distribution providers or other functional entities. Fourteen remaining load-serving entities would be deregistered as they are not registered for any other function. According to NERC, six of the 14 entities are in the TRE region, and "TRE has determined that the removal of these six entities…would not

[44] *See supra* P 32.

pose a reliability gap since these six entities have market participation agreements that can be enforced as market rules." For the remaining eight entities, NERC provides a general assessment that load-serving entity functions will continue to be performed by the de-registered entities, or others, pursuant to tariffs, interconnection agreements, or similar provisions.[45] We find this general explanation to be inadequate. NERC does not provide any specific information regarding the alternative sources of authority, such as responsibilities of entities that will remain on the Compliance Registry to cover the load-serving entity reliability tasks, tariff provisions or other agreements, which NERC represents will ensure the continuation of load-serving entity activities.

39. Moreover, we are concerned whether the gap is more extensive. In particular, the record in the proceeding indicates that the revision of the distribution provider threshold from 25 MW to 75 MW peak load will likely result in the deactivation of more than 100 entities that are currently registered as distribution providers.[46] NERC's technical analysis in support of the proposed elimination of the load-serving entity relies, in part, on distribution providers taking responsibility for compliance with many Reliability Standards currently assigned to load-serving entities.[47] The deactivation of more than 100 distribution providers will likely increase the number of deregistered load-serving entities. NERC's analysis, however, does not address how the deactivation of distribution providers impacts its estimate regarding the number of load-serving entities that would be deregistered and how continuity of responsibility under Reliability Standards will be ensured. As discussed above, we find inadequate NERC's general explanation that deregistered entities will continue to perform load-serving entity-related activities based on tariffs and agreements.

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[45] NERC Petition at 31.

[46] Trade Associations indicate that the proposed 75 MW peak load threshold "could significantly reduce the compliance burden for more than 100 small registered entities (some 25% of the registered [distribution providers])." Trade Associations Comments at 12. *See also* Trade Associations Comments, Att. A (estimating 113 distribution providers have a peak load between 25 and 75 MW, representing 0.7 percent of the total load served).

[47] *See* NERC Petition at 30-31 ("NERC has acknowledged that Distribution Providers should be responsible for compliance with many of the Reliability Standards assigned to Load-Serving Entities"). *See also id*. at 29 ("CIP Version 5 Standards have removed the Load-Serving Entity as an applicable function and substituted the Distribution Provider function").

40. Our finding above that increasing the Registry Criteria threshold for distribution providers from 25 to 75 MW peak load (and that have no other identified, specific materiality to reliability) will not pose a significant risk to the reliability of the Bulk-Power System does not change our concerns here regarding load-serving entities. Although the record indicates that the affected distribution providers represent approximately 0.7 percent share of total load served, it is unknown whether there are higher concentrations within individual balancing authority areas. Further, NERC does not adequately address whether, going forward, all balancing authorities and planners will have the ability to reasonably estimate demand and energy forecast data for areas where the load-serving entity is deregistered. In areas of significant load-growth, the cumulative effect of deregistered entities not having to provide accurate load data projections as required by certain MOD Reliability Standards could have an increasing effect on reliability over time as load increases, e.g., as a result of demand and energy forecast data omitted or not accurately depicted in power system models and assessments.[48]

41. Accordingly, we deny NERC's proposal to remove the load-serving entity function and direct NERC to submit a compliance filing that addresses the gap in its analysis of the proposed elimination of the load-serving entity function, as discussed above. In particular, NERC should provide an adjusted estimate on the number of load-serving entities that would be deregistered. NERC should provide additional information regarding the peak load of such entities on an individual and balancing authority basis.[49] Further, for the load-serving entities for which NERC anticipates deregistration, NERC must provide specific information regarding the alternative sources of authority which will ensure the continuation of load-serving entity reliability activities by either the

[48] *See*, *e.g.*, Reliability Standards MOD-016-1.1 (Actual and Forecast Demands, Net Energy for Load, Controllable DSM); MOD-017-0.1 (Aggregated Actual and Forecast Demands and Net Energy for Load); MOD-018-0 (Reports of Actual and Forecast Demand Data); MOD-019-0.1 (Reporting of Interruptible Demands and Direct Control Load Management); MOD-021-1 (Accounting Methodology for Effects of DSM in Forecasts). Further, Commission-approved MOD-031-1 (Demand and Energy Data) is effective as of July 1, 2016, at which time MOD-016 through 019 and 021 will retire.

[49] We realize that NERC's analysis is based on anticipated conditions and should not be viewed as pre-judging the application of the proposed compliance registry revisions to a specific entity. Further, NERC need not identify (and may mask) entity names in providing details regarding peak load and other relevant data, provided that the data is presented in a useful, understandable manner. In any case, NERC should clearly group data according to balancing authority areas.

deregistered entity or another registered entity. For example, NERC should identify specific tariff provisions and the load-serving entity reliability tasks to which they relate. Likewise, NERC should identify relevant provisions of agreements, market rules or other documents and the load-serving entity reliability tasks to which they relate. If this analysis indicates that gaps remain, NERC should propose alternative means to address identified gaps, such as modifications to specific Reliability Standards or perhaps developing a compliance registry subset similar to the UFLS-only distribution provider category proposed by NERC in its petition.

42. The Commission has two further concerns regarding the proposed elimination of the load-serving entity function. First, NERC should address in the compliance filing its coordination with NAESB to ensure the timely transfer of commercial-related practices affected by the proposed elimination of the load-serving entity function. For example, NERC points out that the RBR proposal would effectively retire Reliability Standard INT-011-1, which applies only to load-serving entities, requiring a load-serving entity "that uses Point to Point Transmission Service for intra-Balancing Authority Area transfers shall submit a Request for Interchange …." While we are persuaded by NERC that this provision is commercial in nature and has minimal reliability implications, we are not persuaded by NERC that such transactions are currently fully covered by NAESB standards that pertain to "e-tagging."[50] Rather, NAESB is currently working to expand e-tagging requirements to include intra-balancing authority transfers.[51] While we provide this one example, NERC should fully address in the compliance filing its coordination with NAESB to address the transition of commercial-related obligations necessitated by the proposed retirement of the load-serving entity function.

43. Second, NERC explains that the impact of removing the load-serving entity function is lessened because NERC has removed – or is in the process of removing – the load-serving entity function from a number of Reliability Standards.[52] NERC anticipates that current standard development projects would propose to remove the load-serving entity as an applicable entity from Reliability Standards EOP-011-1, PRC-010-1, PRC-022-2, as well as multiple TOP and IRO standards. When and if NERC submits one or more petitions for revised Reliability Standards that propose to remove the load-serving entity as an applicable entity, NERC must provide an adequate explanation of how the previous load-serving entities obligations will continue. In particular, an explanation that

[50] NERC Petition at 32. *See also id*. Ex. C (Technical Report) at 10.

[51] *See, e.g.*, Trade Associations Comments, App. B at 3, 4.

[52] *See* NERC Petition at 30.

the removal of the load-serving entity function is consistent with the RBR initiative would be inadequate, if not circular, in light of NERC's rationale in the immediate docket that the impact from eliminating the load-serving entity function is lessened by the removal of the function from Reliability Standards.[53] NERC is responsible to explain in the context of a particular modified Reliability Standard whether removal of the load-serving entity would result in a reliability gap and, if so, how the gap is addressed.

4. Underfrequency Load Shedding-only Distribution Providers

NERC Proposal

44. NERC states that it analyzed the effects from the potential loss of the underfrequency load shedding capability from distribution providers that are less than 75 MW peak load and have no other specific materiality to reliability, but participate in a required underfrequency load shedding program. Such entities are proposed to be subject to registration as a "underfrequency load shedding-only distribution provider."[54] NERC states that a underfrequency load shedding-only distribution provider is a distribution provider that is the responsible entity that owns, controls, or operates underfrequency load shedding protection systems needed to implement a required underfrequency load shedding program designed for the protection of the bulk electric system, but that does not meet any of the other criteria for registration as a distribution provider.[55]

45. NERC states that it surveyed 74 planning coordinators in the United States, representing approximately 800,000 MW of peak load, and received responses from 64 planning coordinators, representing 680,000 MW or 85 percent of U.S. peak load. NERC submits that this sample size is representative of the total population and that planning coordinators representing 472,000 MW of load have underfrequency load shedding programs in which distribution providers under 75 MW participate. According to NERC, the distribution providers located in these planning coordinator areas represent

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[53] *Id*. The TOP/IRO standard drafting team (Project 2014-03) "removed the Load-Serving Entity as an applicable entity following the recent Board of Trustees (Board) action on removing Load-Serving Entity as a functional entity." *See* Consideration of Comments on Project 2014-03 Revisions to TOP and IRO Standards, at 1. *See*: http://www.nerc.com/pa/Stand/Prjct201403RvsnstoTOPandIROStndrds/2014_03_third_posting_comment_report_20141122_response_qr.pdf.

[54] NERC Petition at 40, Exhibit C at 2.

[55] *Id*. at 41 n. 56.

approximately 3,500 MW of load nationwide. NERC explains that assessing the risk in this manner is appropriate because underfrequency load shedding operates on an area basis, and so failure of a few relays does not pose a significant risk. Based on the respondents' data submittals, NERC believes that the reported information regarding small distribution providers' contributions to underfrequency load shedding programs is representative of the NERC-wide distribution, and major concentrations do not exist in the unreported data that significantly exceed those reported on a regional basis or planning coordinator basis.

46. NERC proposes to limit the application of Reliability Standards to underfrequency load shedding-only distribution providers solely with Reliability Standard PRC-006.[56] NERC explains that it based its proposal on its finding that underfrequency load shedding programs in the United States can withstand up to 25 percent of the relays of the small entities failing to operate due to maintenance not being performed in accordance with Reliability Standard PRC-005, without significant negative effects. NERC explains that it excluded Reliability Standard PRC-005 which pertains to protection system maintenance and testing, because, due to technological advances, the majority of modern relays being deployed to the industry today are self-maintaining and self-checking.[57] According to NERC, the possible reliability benefits of continuing to enforce compliance with Reliability Standard PRC-005's 12-year testing requirements by small underfrequency load shedding-only distribution providers is diminished by the risk associated with performing inspection and maintenance.

47. NERC states that it can "apply sub-sets of Reliability Standards through an exercise of its discretion as part of the registration process, to determine whether a particular Reliability Standard or requirement shall apply to an entity."[58] NERC also developed a process for applying for a sub-set of Reliability Standards to underfrequency load shedding-only distribution providers, whereby an entity would be required to apply to the appropriate Regional Entity, and the Regional Entity would issue a decision as to whether underfrequency load shedding-only distribution provider treatment is appropriate. NERC explains that it conducts subsequent reviews and that there is an appeals process to a NERC-led review panel and to the NERC Board Compliance Committee.

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[56] *Id*. at 40.

[57] *Id*. at 41 and Exhibit C Technical Report at 18, 20-21.

[58] NERC Petition at 38-39 (citing *Generator Requirements at the Transmission Interface*, Order No. 785, 144 FERC ¶ 61,221 at PP 52-53 (2013)).

Comments

48. The PSEG Companies do not object to creating a limited set of Reliability Standards applicable to certain distribution providers. However, the PSEG Companies recommend that references to "underfrequency load shedding-only distribution providers" should be removed because this new term is not defined in the NERC Glossary; and the Registry Criteria should not include a list of Reliability Standards applicable to underfrequency load shedding-only distribution providers. Instead, PSEG Companies maintain that a more appropriate vehicle through which to address this issue is to require distribution providers registered solely because they own, control, or operate underfrequency load shedding protection system needed to implement a required underfrequency load shedding program to apply to the panel to limit themselves to a sub-set of Reliability Standards.

Answers

49. NERC explains that there is no requirement for terms used in the Registry Criteria to mirror those in the NERC Glossary. NERC states that any changes that need to be made to the NERC Glossary as a result of the Commission's approval of the NERC petition will go through the standard development process. In addition, NERC explains that entities that qualify as underfrequency load shedding-only distribution providers are a sub-category of a distribution provider and until a Reliability Standard is submitted limiting its applicability to certain functional entities or characteristics, the Commission recognized the registration process is "the preferred method of determining the applicability of Reliability Standards on an entity-by-entity basis."[59]

50. NERC commits to continue to evaluate sub-set lists of Reliability Standards for appropriate entities as it has done for underfrequency load shedding-only distribution providers. However, NERC does not intend to retain all sub-set lists in the NERC Rules of Procedure, rather they will be denoted in the NERC Compliance Registry as to applicable entities. While the Registry Criteria include an initial list for underfrequency load shedding-only distribution providers, NERC explains that any changes to that initial list will be reflected in the entity's NERC Compliance Registry listing. This recognizes the ability for future applicable Reliability Standards to be addressed through the

[59] NERC Answer at 8 n. 28 (citing *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. and Regs. ¶ 31,242 at P 98, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007); Order No. 773, 141 FERC ¶ 61,236, at P 52 (2012); Order No. 785, 144 FERC ¶ 61,221 (2013)).

Reliability Standard Development Process. Further, regarding the PSEG Companies' assertion that every distribution provider must first proceed through the NERC-led panel to be granted the already determined initial underfrequency load shedding-only distribution provider sub-set list, NERC contends that this introduces a significant unjustified administrative burden.

51. Trade Associations answer that the PSEG Companies improperly seek to transform the NERC Glossary into a "straitjacket barring NERC from efficient registration practices."[60] Trade Associations argue that the PSEG Companies provides no basis for imposing an underfrequency load shedding-only distribution provider implementation process, and assert that such a process is not a good use of resources with regard to very small distribution providers.

Commission Determination

52. We approve NERC's proposal regarding underfrequency load shedding-only distribution providers. We find that limiting the scope of the standards applicable to particular registered entities is consistent with the Commission's recognition for NERC to determine the scope of the standards applicable to particular registered entities on a case-by-case basis.[61]

53. NERC states that, pursuant to its proposal, underfrequency load shedding-only distribution providers will be responsible to comply with a subset of Reliability Standards that include a single standard, PRC-006 (and regional versions of PRC-006). The Commission believes that an additional Reliability Standard, PRC-005, pertaining to protection system maintenance, should continue to apply to underfrequency load shedding-only distribution providers. We are not persuaded by NERC's rationale, set forth above, for determining that PRC-005 should no longer apply.

54. Currently, Reliability Standard PRC-005 applies to a "Distribution Provider that owns a transmission Protection System." Regarding NERC's explanation that it excluded Reliability Standard PRC-005 because the most modern relays are self-maintaining and self-checking, NERC's risk assessment does not provide boundary thresholds for the appropriate amount of risk to the system due to failure as opposed to the once in 12 year "risk associated with the mere act of opening up a relay for inspection and

[60] Trade Associations Answer at 5.

[61] *See, e.g.*, Order No. 773, 141 FERC ¶ 61,236 at P 52.

maintenance."[62] NERC's proposal to register distribution providers with less than 75 MW peak load as underfrequency load shedding-only distribution provider underscores that the underfrequency load shedding relays are important to reliability. Thus, it is important to maintain underfrequency load shedding relays to operate as designed. NERC states that the risk to the bulk electric system associated with failures of underfrequency load shedding systems for these small entities due to maintenance is low, NERC therefore recognizes there is a risk of actually performing maintenance and testing of relays. On this basis, NERC concludes that the benefit of compliance is diminished by the risk associated with performing inspection and maintenance. However, NERC has not demonstrated that the risk posed by maintenance efforts generally outweighs the risk posed by not performing maintenance, or that the subset of devices at issue here warrants a different balance of these risks than other devices covered by Reliability Standard PRC-005. Further, NERC reports that distribution providers have a history of non-compliance with Reliability Standard PRC-005 suggesting a need to maintain mandatory maintenance and testing requirements.[63] Requiring underfrequency load shedding-only distribution providers to continue to comply with Reliability Standard PRC-005 should not constitute an undue compliance burden because most relays currently in use are microprocessor based and, thus, require maintenance only once in 12 years.

55. While Trade Associations support NERC's omission of Reliability Standard PRC-005, the Commission believes that, if distribution providers that own underfrequency load shedding relays for small loads are important enough to register, as NERC proposes, then these relays are also important enough to maintain and test just like other relays covered under Reliability Standard PRC-005. Therefore, the Commission directs NERC to include Reliability Standard PRC-005 as applicable to underfrequency load shedding-only distribution providers.

56. The PSEG Companies suggests that all references to "underfrequency load shedding-only distribution provider" should be removed because this term is not defined in the NERC Glossary. As NERC explains, there is no requirement for terms used in the Registry Criteria to mirror those in the NERC Glossary; the registration process is developed and maintained pursuant to the NERC Rules of Procedure. NERC indicates that it will make any necessary changes to the NERC Glossary and notes that it has initiated a project to align NERC Glossary terms with definitions used in the Rules of

[62] NERC Petition at 41.

[63] NERC indicates that all eight violations processed since 2007 for entities that may potentially be deactivated for the distribution provider function were of Reliability Standard PRC-005. NERC Petition, Exh. C, Technical Report at 15.

Procedure. Therefore, we will not direct NERC to adopt the PSEG Companies' suggestion as we find NERC's explanations and commitments reasonable.

5. Procedural Changes to the Registration Process

57. NERC proposes procedural changes to its registration process including: (1) the establishment of a materiality test for registration (including a non-exhaustive list of factors), which delineates the procedures and criteria for evaluating whether an entity has a material impact on reliability; (2) a process to review registration, deactivation and deregistration decisions, as well as requests for sub-set lists of Reliability Standards.[64] According to NERC, these proposed procedural improvements provide additional clarity and transparency to the registration requirements, roles, and responsibilities.

a. Materiality Test

NERC Petition

58. At the end of the Registry Criteria, NERC provides "notes" that state that the specified criteria "are general criteria only." A Regional Entity thus may register an entity that does not meet the specified criteria if the Regional Entity "believes and can reasonably demonstrate that the organization is a bulk power system owner, or operates, or uses bulk power system assets, and is material to the reliability of the bulk power system."[65] Further, the Registry Criteria provide that a class of entities, each of which would be individually excluded, may nevertheless be registered based on their aggregate impact on Bulk-Power System reliability.

59. NERC proposes to add a new materiality test to the notes, which is comprised of four "non-exclusive" factors for consideration regarding an entity's material impact on the reliability of the bulk electric system. According to NERC, these factors recognize NERC's existing authority to limit the compliance obligations of a given entity to sub-sets of Reliability Standards which may specify the applicable Requirements/sub-Requirements.

[64] NERC Petition at 45-49.

[65] NERC Registry Criteria, Notes to Criteria, note 1 (footnote excluded).

Comments

60. ELCON supports the materiality test for registration to mitigate the risk of unnecessary and inappropriate registration of retail, load-only manufacturing plants, especially for those entities that otherwise do not meet the exclusion criteria of the bulk electric system definition. Trade Associations support the materiality test. Trade Associations explain that a materiality impact determination already exists for registration-related activities and that the non-exclusive factors add transparency and reduce regulatory uncertainty in the registration process. On the other hand, the PSEG Companies and the QF Parties argue that the materiality test should be clarified. PSEG Companies argues that the factors are incomplete or summarize topics addressed in Reliability Standards. PSEG Companies further contends that NERC should either eliminate the list of the four non-exclusive factors or consider alternative language provided by the PSEG Companies. Similarly, the QF Parties state that the criteria are ambiguous because they appear to cover both generators and transmission entities. QF Parties contend that the criteria should be clarified to identify which generators are affected and which other generators will be assessed for an impact so that the criteria can be practically applied.

Answers

61. NERC responds that the materiality test articulates a non-exclusive list of factors whose application would vary depending on facts and circumstances of a given matter, taking into account risk-based considerations in reaching a decision. Trade Associations add that the non-exclusive factors are intended to provide guidance to registered entities and Regional Entities as to the types of factors to be considered by the NERC-led multi-regional panel in assessing material impact on a case-by-case basis.

Commission Determination

62. We approve this aspect of NERC's RBR petition. Currently, the Registry Criteria contains a determination of material impact in the "notes" to the criteria, and NERC's proposal to add non-exclusive factors is intended to provide guidance and clarity to those determinations. The Commission approves the revisions as guidance for registered entities and Regional Entities regarding the types of factors to be considered by the NERC-led multi-regional panel in assessing material impact on a case-by-case basis.[66]

[66] NERC's proposed guidance is similar to NERC's form entitled "Detailed Information to Support an Exception Request" that entities use to support requests for exception from the "bulk electric system" definition. In that case, the form was intended to provide the needed flexibility to allow Regional Entities to make a recommendation of

(continued ...)

We believe that the non-exclusive set of factors will provide useful guidance for making a materiality determination. In addition, the Commission is persuaded by NERC's explanation that risk-based registration contemplates that application of the materiality test factors would vary depending on facts and circumstances. The analysis also takes into account risk-based considerations in reaching a decision on materiality. We agree with NERC that the factors are relevant to assessing an entity's materiality to reliability but not determinative of an entity's materiality. Additional factors may be relevant based on specific facts and circumstances. This approach is similar to the bulk electric system definition exception process where after application of the bright-line criteria, exceptions can be justified.[67]

b. Review Process for Registration Decisions

NERC Petition

63. NERC proposes to establish a NERC-led, centralized review panel to evaluate requests for (1) deactivation of, or decisions not to register, an entity; (2) requests to add an entity that does not meet (i.e., falls below) the Registry Criteria; (3) disputes regarding the application of the Registration Criteria; and (4) requests for a sub-set list of applicable Reliability Standards. NERC explains that the panel will help maintain consistency and oversight in registration among NERC and the Regional Entities. The NERC-led review panel would be comprised of a standing pool of individuals with relevant expertise from NERC and each of the Regional Entities. Once the review panel makes a decision, the decision would be posted publicly on the NERC website.

Comments

64. Trade Associations agree with the development of a NERC-led multi-regional panel, stating that this enhancement should drive consistency in processes and outcomes across the ERO enterprise.

65. PSEG Companies argues that the NERC-led panel which NERC states "may also include a review of individual and aggregate system-wide risks…," should be required to review aggregate system-wide risks, rather than having the option as is currently drafted. According to PSEG Companies, if the panel makes a decision that a registered entity

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whether or not an element is necessary for the reliable operation of the interconnected transmission network. *See* Order No. 773, 141 FERC ¶ 61,236 at PP 298-301.

[67] NERC Petition, Exh. C Technical Report at 17.

need not comply with several otherwise-applicable Reliability Standards because the exception would not have a material impact on reliability, other registered entities may apply for the same treatment because their circumstances are similar. PSEG Companies contends that if the panel considers the aggregate impact of all similarly situated entities together, it may arrive at a different decision. Therefore, PSEG Companies recommends that NERC require the panel to identify similarly situated entities after receiving a request by an applicant for a registration or standards applicability decision. In addition, PSEG Companies notes that the NERC-led panel may approve deactivation of an entity or approve an entity for a sub-set list of applicable Reliability Standards by application of the materiality test. However, PSEG Companies expresses concern that an entity may be reactivated for the function for which it was deactivated, or have its approved sub-set list of applicable Reliability Standards withdrawn or expanded, without application of the materiality test.

Answers

66. NERC responds that the panel will analyze individual and aggregate issues as warranted by soliciting input from host or neighboring entities. According to NERC, the panel will identify the factors considered in the decisions, which will be posted publicly on the NERC website. With regard to reactivation, NERC explains that reactivation of any entity occurs when there is a change in circumstances or where a new risk to reliability is identified after an entity has been deactivated. NERC explains that the materiality test is applicable to reactivation as well.

Commission Determination

67. The Commission approves the review process for registration decisions. We find that the panel will help maintain consistency and oversight in registration among NERC and the Regional Entities and that NERC's explanations and clarifications regarding the process in response to commenters are reasonable and add clarity to the process. The NERC-led review panel will issue a decision that will be made publicly available and will identify all factors that were applied and considered for that matter, providing appropriate transparency.

68. However, we conclude that the NERC-led panel must consider both individual and aggregate system-wide risks when reviewing a registry matter. We agree with PSEG Companies that consideration of the aggregate risk of a possible entity deregistration, including the possible cumulative effect of multiple deregistrations, is fundamental to ensuring that panel decisions do not lead to increased risk to the reliability of the bulk electric system. We are not persuaded by NERC's explanation, i.e., the panel will analyze individual and aggregate issues as warranted by soliciting input from host or neighboring entities. NERC's suggestion appears both *ad hoc* in approach and limited in scope. Accordingly, to ensure that review panels perform a consistent and thorough

review of both individual *and* aggregate system-wide risks when reviewing a registry matter, we direct NERC to modify proposed Section III.D.9, Appendix 5A of the NERC Rules of Procedure to substitute "shall" for "may," to state that "[t]he NERC-led review panel *shall* also include a review of individual and aggregate system-wide risks…" We direct NERC to address this modification in the compliance filing that NERC must file 60 days after the date of issuance of this order. We anticipate that in many circumstances consideration of aggregate risks will be straightforward.

69. Finally, we note that proposed Sections III.D.11 and 13 of Appendix 5A provides that review panel decisions will be posted on the NERC website and that the NERC Board of Trustees Compliance Committee (BOTCC) will resolve any appeals of registry matters as set forth in Section V of Appendix 5A. While the BOTCC review process anticipates a possible appeal to the Commission, it does not provide an opportunity for Commission review without such appeal. Accordingly, to provide the Commission with an opportunity for review where no appeal occurs, NERC must provide notice to the Commission when a review panel decision is posted. Similar to the process for review of "find, fix and track" compliance posting as well as "compliance exception" postings,[68] the Commission will review such matters and determine within 60 days of receiving notice from NERC whether any formal Commission review is warranted. If the Commission takes no action within 60 days, the Commission will consider the matter closed. We anticipate that Commission review of panel decisions would be a rare occurrence. However, we believe that this opportunity for Commission review provides an important "backstop" to ensure that individual registry matters processed under RBR are decided in a consistent matter with an overall view of providing for the reliability of the bulk electric system.

The Commission orders:

(A) The Commission hereby approves in part, and denies in part, NERC's RBR petition, as set forth in the body of this order.

(B) NERC is hereby directed to make a compliance filing, as discussed in the body of this order, within 60 days of the date of the issuance of this order.

(C) NERC is hereby directed to submit an informational filing, as discussed in the body of this order, within 12 months of the date of the issuance of this order.

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[68] *See, e.g.*, *North American Electric Reliability Corp.*, 150 FERC ¶ 61,108 at P 47 (2015).

(D) NERC is hereby direct to provide the Commission with notice of review panel discussions, as discussed in the body of this order.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

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FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD15-2-000

March 4, 2015

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005

Attention: Milena Yordanova
Associate Counsel for North American Electric Reliability Corporation

Reference: Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard PRC-006-2

Dear Ms. Yordanova:

On December 15, 2014, the North American Electric Reliability Corporation (NERC) filed a petition seeking approval of the proposed Reliability Standard PRC-006-2 (Automatic Underfrequency Load Shedding), the associated implementation plan, the violation risk factors, and violation security levels and the retirement of currently effective Reliability Standard PRC-006-1.

The purpose of proposed Reliability Standard PRC-006-2 is to establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures. Proposed Reliability Standard PRC-006-2 states that it is applicable to planning coordinators, UFLS entities (a term defined in the proposed Reliability Standard), and transmission owners that own elements identified in the underfrequency load shedding programs established by planning coordinators. The petition maintains that the proposed Reliability Standard contains changes that address the Commission's concern in Order

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No. 763 relating to Requirement R9 of PRC-006-1.[1] In Order No. 763, the Commission approved Reliability Standard PRC-006-1. In addition, the Commission directed NERC to include explicit language in a subsequent version of the Reliability Standard clarifying that applicable entities are required to implement corrective actions identified by the planning coordinator in accordance with a schedule established by the same planning coordinator.[2] The petition states that this is accomplished by additional language in Reliability Standard PRC-006-2, Requirements R9 and R10, and the introduction of a new Requirement R15. The revisions also place deadlines for corrective action plans to be developed by the planning coordinator. The petition states that these proposed deadlines are within the timeframes identified in Requirements R4, R5 or R12.

NERC's filing was noticed on December 17, 2014, with interventions, comments and protests due on or before January 16, 2015. Dominion Resources Services, Inc. filed a timely motion to intervene raising no issues.

NERC's uncontested filing is hereby approved pursuant to the relevant authority delegated to the Director, Office of Electric Reliability under 18 C.F.R. § 375.303 (2014), effective as of the date of this Order.

This action shall not be construed as approving any other application, including proposed revisions of Electric Reliability Organization or Regional Entity rules or procedures pursuant to 18 C.F.R. § 375.303(a)(2)(i). Such action shall not be deemed as recognition of any claimed right or obligation associated therewith and such action is without prejudice to any findings or orders that have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Electric Reliability Organization or any Regional Entity.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713 (2014).

Sincerely,

Michael Bardee, Director
Office of Electric Reliability

[1] *Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards*, Order No. 763, 139 FERC ¶ 61,098, *order granting clarification*, 140 FERC ¶ 61,164 (2012).

[2] Order No. 763, 139 FERC ¶ 61,098 at P 48.

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Document Content(s)

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150 FERC ¶ 61,164
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Cheryl A. LaFleur, Chairman;
Philip D. Moeller, Tony Clark,
Norman C. Bay, and Colette D. Honorable.

North American Electric Reliability Corporation Docket No. RD15-1-000

ORDER APPROVING TWO REGIONAL RELIABILITY STANDARDS

(Issued March 3, 2015)

1. On December 15, 2014, the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), and Western Electricity Coordinating Council (WECC) submitted a joint petition seeking approval of proposed WECC regional Reliability Standards VAR-002-WECC-2 (Automatic Voltage Regulators) and VAR-501-WECC-2 (Power System Stabilizer). As discussed below, we approve the proposed WECC regional Reliability Standards.

I. Background

2. Section 215(d) of the Federal Power Act (FPA) requires the ERO to develop mandatory and enforceable Reliability Standards that are subject to Commission review and approval.[1] Section 215(d)(2) of the FPA states that the Commission may approve, by rule or order, a proposed Reliability Standard or modification to a Reliability Standard if it determines that the Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest. Once approved, the Reliability Standard may be enforced by the ERO, subject to Commission oversight, or by the Commission independently.[2]

[1] 16 U.S.C. § 824o(d) (2012).

[2] *Id.* § 824o(e).

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3. A Regional Entity may develop a Reliability Standard for Commission approval to be effective in that region only.[3] In Order No. 672, the Commission stated that:

> As a general matter, we will accept the following two types of regional differences, provided they are otherwise just, reasonable, not unduly discriminatory or preferential and in the public interest, as required under the statute: (1) a regional difference that is more stringent than the continent-wide Reliability Standard, including a regional difference that addresses matters that the continent-wide Reliability Standard does not; and (2) a regional Reliability Standard that is necessitated by a physical difference in the Bulk-Power System.[4]

4. On April 19, 2007, the Commission accepted delegation agreements between NERC and each of the eight Regional Entities. In the order, the Commission accepted WECC as a Regional Entity.[5]

5. In Order No. 693, the Commission approved NERC continent-wide Reliability Standard VAR-002-1 (Generator Operation for Maintaining Network Voltage Schedules).[6] On June 8, 2007, the Commission approved eight WECC regional Reliability Standards for the Western Interconnection, including regional Reliability Standards WECC-VAR-STD-002a-1 (Automatic Voltage Regulators) and WECC-VAR-

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[3] *Id.* § 824o(e)(4). A Regional Entity is an entity that has been approved by the Commission to enforce Reliability Standards under delegated authority from the ERO. *See* 16 U.S.C. §§ 824o(a)(7) and (e)(4).

[4] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 291, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[5] *North American Electric Reliability Corp.*, 119 FERC ¶ 61,060, *order on reh'g*, 120 FERC ¶ 61,260 (2007).

[6] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

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STD-002b-1 (Power System Stabilizer).[7] In Order No. 751, the Commission approved revisions to regional Reliability Standards WECC-VAR-STD-002a-1 and WECC VAR-STD-002b-1, which were re-designated VAR-002-WECC-1 and VAR-501-WECC-1 respectively.[8]

II. Petition

6. NERC and WECC state in the petition that the proposed regional Reliability Standards arise out of NERC's "P 81 project," which was a response to paragraph 81 of the Commission's March 15, 2012 order conditionally accepting NERC's Find, Fix, Track and Report program.[9] Petitioners explain that the P 81 project involved identifying requirements that could be removed from Reliability Standards without impacting the reliability of the Bulk-Power System. Petitioners state that the P 81 project identified Requirement R2 in WECC regional Reliability Standards VAR-002-WECC-1 and VAR-501-WECC-1 as candidates for retirement.

7. Petitioners explain that the proposed regional Reliability Standards revise currently-effective regional Reliability Standards VAR-002-WECC-1 and VAR-501-WECC-1 to remove an administrative Requirement R2 in each, which requires documentation relating to the exclusion of hours provisions of Requirement R1.[10] Petitioners state that the proposed regional Reliability Standards transfer the

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[7] *North American Electric Reliability Corp.*, 119 FERC ¶ 61,260 (2007).

[8] *Version One Regional Reliability Standards for Facilities Design, Connections, and Maintenance; Protection and Control; and Voltage and Reactive*, Order No. 751, 135 FERC ¶ 61,061 (2011).

[9] *See North American Electric Reliability Corp.*, 138 FERC ¶ 61,193, at P 81 (2012) ("If NERC believes that specific Reliability Standards or specific requirements within certain Standards should be revised or removed, we invite NERC to make specific proposals to the Commission identifying the Standards or requirements and setting forth in detail the technical basis for its belief.").

[10] Regional Reliability Standard VAR-002-WECC-1, Requirement R2 currently requires that generator operators and transmission operators "shall have documentation identifying the number of hours excluded for each requirement in R1.1 through R1.10." Regional Reliability Standard VAR-501-WECC-1 currently includes similar language requiring generator operators to have "documentation identifying the number of hours excluded for each requirement in R1.1 through R1.12."

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documentation language to Measure M1 in Requirement R1 of each regional Reliability Standard. Petitioners further state that an additional provision, which was formerly located in Measure M2, has been added to Measure M1 in each proposed regional Reliability Standard requiring that the dates of outages be provided with currently required quarterly reports. Petitioners also note that the proposed regional Reliability Standards include non-substantive formatting changes throughout the document to conform to NERC drafting conventions.

8. Petitioners maintain that the substantive requirements in both proposed regional Reliability Standards have not changed and remain more stringent than the continent-wide Reliability Standard VAR-002. Petitioners contend that the proposed regional Reliability Standards achieve the same reliability purpose of the prior versions in that regional Reliability Standard VAR-002-WECC-2 will ensure that automatic voltage regulators on synchronous generators and condensers are kept in service and controlling voltage and regional Reliability Standard VAR-501-WECC-2 will ensure that power system stabilizers on synchronous generators are kept in service. Petitioners explain that, with exception of the removal of violation risk factors and violation severity levels for the deleted Requirement R2, the violation risk factors and violation severity levels in the current and proposed regional Reliability Standards are the same. Petitioners propose an implementation date of the first day of the first quarter following applicable regulatory approval.

III. Notice of Filing

9. Notice of NERC's filing was published in the Federal Register, 79 Fed. Reg. 76,315 (2014), with interventions and protests due on or before January 15, 2015. Dominion Resources Services, Inc. (Dominion) filed timely comments.

10. Dominion states that it "does not oppose the petition" but that it is concerned that the proposed regional Reliability Standards "do not include a waiver or variance from the 'equivalent' continent-wide standard or are not incorporated as specific requirements (applicable only within that region) into the continent-wide standard."[11] Dominion also contends that the proposed regional Reliability Standards are not "more stringent than the current continent-wide standard and thus should not be approved."[12]

[11] Dominion Comments at 3.

[12] *Id.*

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IV. Discussion

11. The Commission approves proposed WECC regional Reliability Standards VAR-002-WECC-2 and VAR-501-WECC-2 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. In approving previous versions of the regional Reliability Standards, the Commission determined that they, respectively, were more stringent than the then-current continent-wide NERC Reliability Standard VAR-002 and addressed issues not addressed in the continent-wide NERC Reliability Standards.[13] The revisions NERC and WECC propose here do not affect the substantive requirements of the regional Reliability Standards. Instead, the proposed revisions merely transfer the documentation requirement in Requirement R2 of each regional Reliability Standard to the Measure section of Requirement R1 of each regional Reliability Standard and move a provision currently in Measure M2 to Measure M1. Accordingly, we determine that the proposed revisions are just, reasonable, not unduly discriminatory or preferential, and in the public interest. In addition, we approve the violation risk factors, violation severity levels, and implementation plan proposed by NERC and WECC.

12. We reject the comments submitted by Dominion. Rather than address the specific revisions proposed by NERC and WECC in this proceeding, Dominion's comments largely address issues decided by the Commission in orders approving previous versions of the regional Reliability Standards.[14]

13. Dominion states that the current NERC continent-wide Reliability Standard VAR-002-3 is more stringent than proposed regional Reliability Standard VAR-002-WECC-2 because the NERC continent-wide standard requires automatic voltage regulators to be in service "100 percent of the time unless it has been instructed by the [transmission

[13] *See North American Electric Reliability Corp.*, 119 FERC ¶ 61,260 at PP 118, 122; Order No. 751, 135 FERC ¶ 61,061 at PP 58, 72, 85, 99, 117.

[14] We have not, until now, had occasion to consider WECC regional Reliability Standards VAR-002-WECC and VAR-501-WECC in view of current NERC continent-wide Reliability Standard VAR-002-3. However, as discussed in this order, we find that the justifications for approving WECC regional Reliability Standards VAR-002-WECC-1 and VAR-501-WECC-1 articulated in Order No. 751 are equally applicable to this matter and thus justify our approval of WECC regional Reliability Standards VAR-002-WECC-2 and VAR-501-WECC-2 in view of NERC continent-wide Reliability Standard VAR-002-3.

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operator] to operate in a different manner, whereas the requirement for the regional standard is 98 percent of the hours."[15]

14. In approving the first version of the regional Reliability Standard, the Commission stated that "WECC-VAR-STD-002a-1 requires all synchronous generators to have their voltage regulator in service at all time with only exceptions for specified circumstances … [whereas] [t]he related NERC Reliability Standard VAR-002-1, permits a generator to remove its automatic voltage regulator from service for additional reasons."[16] This justification is equally applicable to proposed regional Reliability Standard VAR-002-WECC-2 when compared to the current version of the NERC continent-wide Reliability Standard VAR-002-3. As with currently-effective regional Reliability Standard VAR-002-WECC-1, proposed regional Reliability Standard VAR-002-WECC-2 requires automatic voltage regulators to be in service and in automatic voltage control mode 98 percent of all operating hours for synchronous generators or synchronous condensers subject to specifically enumerated exceptions. By contrast, Reliability Standard VAR-002-3 permits a generator operator to operate without its automatic voltage regulator in service and controlling voltage if: (1) directed by its transmission operator; (2) the generator is exempted by the transmission operator; (3) the generator operator has informed the transmission operator that the generator is being operated in start-up, shutdown, or testing mode pursuant to a realtime communication or a procedure that was previously provided to the transmission operator; or (4) the generator operator has informed the transmission operator that the generator is not being operated in automatic voltage control mode or in the control mode that was instructed by the transmission operator for a reason other than start-up, shutdown, or testing. Because of the broader exceptions in Reliability Standard VAR-002-3, and particularly the exception allowing generator operators not to operate in automatic voltage control mode or in the control mode that was instructed by the transmission operator for a reason other than start-up, shutdown, or testing, we determine that the 98 percent requirement in regional Reliability Standard VAR-002-WECC-2, Requirement R1 is more stringent than the current NERC continent-wide Reliability Standard.[17]

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[15] Dominion Comments at 4.

[16] *See North American Electric Reliability Corp.*, 119 FERC ¶ 61,260 at P 116.

[17] As this proceeding involves proposed WECC Reliability Standards VAR-002-WECC-2 and VAR-501-WECC-2, we will not address Dominion's request to interpret the NERC continent-wide Reliability Standard VAR-002-3.

20150303-3045 FERC PDF (Unofficial) 03/03/2015

15. Dominion also states that Reliability Standard VAR-002-3, Requirement R3 is more stringent than proposed regional Reliability Standard VAR-501-WECC-2, Requirement R1. Dominion maintains that, while the proposed regional Reliability Standard requires power system stabilizers on synchronous generators to be in service 98 percent of the operating hours, Reliability Standard VAR-002-3 "requires the [generator operator] to notify its associated [transmission operator] of a status change on the [power system stabilizer] system within 30 minutes of change."[18] However, requiring a generator operator to notify its transmission operator of a status change on the power system stabilizer system is not the same and, indeed, is less stringent than requiring generator operators to have their power system stabilizers in service 98 percent of all operating hours for synchronous generators equipped with such devices. We also note that, as remains the case here, the Commission's previous orders approving prior versions of the WECC regional Reliability Standards determined that there was no corresponding NERC continent-wide Reliability Standard to this regional Reliability Standard. Accordingly, we determine that proposed regional Reliability Standard VAR-501-WECC-2 is more stringent than any requirement in the NERC continent-wide Reliability Standards.

16. Finally, we disagree with Dominion that there is a need to include a waiver or variance from NERC continent-wide Reliability Standard VAR-002-3 because of the proposed regional Reliability Standards. Dominion's concern that "a company may not implement the proper compliance process when trying to comply with both a regional standard and a continent-wide one" finds no support in the record.[19] No entity in the Western Interconnection potentially subject to the proposed regional Reliability Standards filed comments in response to NERC's and WECC's petition, let alone expressed any concern regarding compliance with the continent-wide and regional Reliability Standards.[20] Moreover, applicable entities in the Western Interconnection are already complying with NERC continent-wide Reliability Standard VAR-002-3 and the currently-effective regional Reliability Standards VAR-002-WECC-1 and VAR-501-WECC-1.

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[18] Dominion Comments at 5.

[19] *Id.* at 6.

[20] Dominion acknowledges that the proposed regional Reliability Standards apply only to the WECC Region and that Dominion is not currently registered in the WECC Region. Dominion Comments at 3.

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V. Information Collection

17. The Office of Management and Budget (OMB) regulations require approval of certain information collection requirements imposed by agency actions.[21] Upon approval of a collection of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirement of this order will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number. The Paperwork Reduction Act[22] requires each federal agency to seek and obtain OMB approval before undertaking a collection of information directed to ten or more persons, or continuing a collection for which OMB approval and validity of the control number are about to expire.[23]

18. The Commission approved regional Reliability Standards VAR-002-WECC-1 and VAR-501-WECC-1 in Order No. 751. The proposed regional Reliability Standard VAR-002-WECC-2 and VAR-501-WECC-2 information collection requirements are a non-material or non-substantive change to the currently-approved collection in Order No. 751. Accordingly, we will submit this order to OMB for informational purposes only.

The Commission orders:

The Commission hereby approves WECC regional Reliability Standards VAR-002-WECC-2 and VAR-501-WECC-2, the associated violation severity levels and violation risk factors, and implementation plan, as discussed in this order.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

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[21] 5 C.F.R. § 1320.10 (2012).

[22] 44 U.S.C. § 3501-20.

[23] 44 U.S.C. § 3502(3)(A)(i), 44 U.S.C. § 3507(a)(3).

Document Content(s)

RD15-1-000.DOCX.....1-8

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

SUNSHINE ACT MEETING NOTICE

April 9, 2015

The following notice of meeting is published pursuant to section 3(a) of the government in the Sunshine Act (Pub. L. No. 94-409), 5 U.S.C. 552b:

AGENCY HOLDING MEETING:	FEDERAL ENERGY REGULATORY COMMISSION
DATE AND TIME:	April 16, 2015 10:00 A.M.
PLACE:	Room 2C 888 First Street, N.E. Washington, D.C. 20426
STATUS:	OPEN
MATTERS TO BE CONSIDERED:	Agenda * NOTE - Items listed on the agenda may be deleted without further notice.
CONTACT PERSON FOR MORE INFORMATION:	Kimberly D. Bose Secretary Telephone (202) 502-8400 For a recorded message listing items struck from or added to the meeting, call (202) 502-8627.

This is a list of matters to be considered by the Commission. It does not include a listing of all documents relevant to the items on the agenda. All public documents, however, may be viewed on line at the Commission's website at http://www.ferc.gov using the eLibrary link, or may be examined in the Commission's Public Reference Room.

1016TH - MEETING

REGULAR MEETING

April 16, 2015

10:00 AM

Item No	Docket No.	Company
		ADMINISTRATIVE
A-1	AD02-1-000	Agency Business Matters
A-2	AD02-7-000	Customer Matters, Reliability, Security and Market Operations
A-3	AD15-12-000	Transmission Investment Metrics
		ELECTRIC
E-1	RM14-13-000	Communications Reliability Standards
E-2	AD15-11-000	Electronic Filing Protocols for Commission Forms
E-3	RM14-10-000	Real Power Balancing Control Performance Reliability Standard
E-4	RM05-5-024	Standards for Business Practices and Communication Protocols for Public Utilities
E-5	RM15-9-000	Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance Reliability Standard
E-6	RM15-4-000	Disturbance Monitoring and Reporting Requirements Reliability Standard
E-7	AD15-6-000	Grand River Dam Authority
E-8	ER15-418-001	New England Power Company
E-9	OMITTED	
E-10	OMITTED	
E-11	QM15-1-000	Virginia Electric and Power Company
E-12	ER15-910-000	Consumers Energy Company
E-13	ER15-976-000	Wolverine Power Supply Cooperative, Inc.

E-14	OMITTED	
E-15	ER12-91-008 ER12-92-008	PJM Interconnection, L.L.C., Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.
E-16	EL15-30-000	San Francisco Bay Area Rapid Transit District v. Pacific Gas and Electric Company
E-17	ER13-102-005 ER13-102-006	New York Independent System Operator, Inc.
E-18	EC12-15-001	Michigan Electric Transmission Company, LLC
E-19	EL11-42-001	Astoria Generating Company L.P. NRG Power Marketing LLC Arthur Kill Power, LLC Astoria Gas Turbine Power LLC Dunkirk Power LLC Huntley Power LLC Oswego Harbor Power LLC and TC Ravenswood, LLC v. New York Independent System Operator, Inc.
	ER12-2414-000 ER12-2414-001 ER12-2414-002	New York Independent System Operator, Inc.
E-20	EL11-50-001	Astoria Generating Company L.P. and TC Ravenswood, LLC v. New York Independent System Operator, Inc.
E-21	ER13-366-004 ER13-366-005 ER13-367-002	Southwest Power Pool, Inc.

MISCELLANEOUS

M-1	RM14-2-000	Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities

GAS

G-1	PL15-1-000	Cost Recovery Mechanisms for Modernization of Natural Gas Facilities

HYDRO

H-1	P-2305-044	Sabine River Authority of Texas Sabine River Authority, State of Louisiana

CERTIFICATES

C-1	CP14-503-000	Enable Gas Transmission, LLC
C-2	CP14-87-001	Southeast Supply Header, LLC
C-3	RP14-638-000	Atmos Energy Corporation v. American Midstream (Midla), LLC
	CP14-125-000 CP14-126-000 RP14-689-000 RP14-689-001 RP14-1049-000 RP14-1049-001 RP14-1049-002 (not consolidated)	American Midstream (Midla), LLC

Kimberly D. Bose,
Secretary.

A free webcast of this event is available through www.ferc.gov. Anyone with Internet access who desires to view this event can do so by navigating to www.ferc.gov's Calendar of Events and locating this event in the Calendar. The event will contain a link to its webcast. The Capitol Connection provides technical support for the free webcasts. It also offers access to this event via television in the DC area and via phone bridge for a fee. If you have any questions, visit www.CapitolConnection.org or contact Danelle Springer or David Reininger at 703-993-3100.

Immediately following the conclusion of the Commission Meeting, a press briefing will be held in the Commission Meeting Room. Members of the public may view this briefing in the designated overflow room. This statement is intended to notify the public that the press briefings that follow Commission meetings may now be viewed remotely at Commission headquarters, but will not be telecast through the Capitol Connection service.

151 FERC ¶ 61,026
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM15-9-000]

Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance Reliability Standard

(Issued April 16, 2015)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: Pursuant to the Federal Power Act, the Commission proposes to approve a revised Reliability Standard, PRC-005-4 (Protection System, Automatic Reclosing and Sudden Pressure Relaying Maintenance), developed and submitted by the North American Electric Reliability Corporation (NERC). In addition, the Commission proposes to approve one new definition and four revised definitions referenced in the proposed Reliability Standard, as well as NERC's proposed violation risk factors, violation severity levels, and implementation plan. Consistent with Order No. 758, the proposed Reliability Standard requires applicable entities to test and maintain certain sudden pressure relays as part of a protection system maintenance program.

DATES: Comments are due **[INSERT DATE 60 days after publication in the FEDERAL REGISTER]**

ADDRESSES: Comments, identified by docket number, may be filed in the following ways:

- Electronic Filing through http://www.ferc.gov. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- Mail/Hand Delivery: Those unable to file electronically may mail or hand-deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

151 FERC ¶ 61,026
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance Reliability Standard	Docket No. RM15-9-000

NOTICE OF PROPOSED RULEMAKING

(Issued April 16, 2015)

1. Pursuant to section 215 of the Federal Power Act (FPA),[1] the Commission proposes to approve a revised Reliability Standard, PRC-005-4 (Protection System, Automatic Reclosing and Sudden Pressure Relaying Maintenance), developed and submitted by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO). In addition, the Commission proposes to approve one new definition and four revised definitions referenced in the proposed Reliability Standard, as well as NERC's proposed violation risk factors, violation severity levels, and implementation plan. Consistent with Order No. 758,[2] the proposed Reliability Standard requires applicable entities to test and maintain certain sudden pressure relays as part of a protection system maintenance program.

[1] 16 U.S.C. 824o (2012).

[2] *Interpretation of Protection System Reliability Standard*, Order No. 758, 138 FERC ¶ 61,094, *clarification denied*, 139 FERC ¶ 61,227 (2012).

I. Background

A. Regulatory Background

2. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval.[3] Once approved, the Reliability Standards may be enforced by the ERO subject to Commission oversight, or by the Commission independently.[4] In 2006, the Commission certified NERC as the ERO pursuant to FPA section 215.[5]

3. In 2007, the Commission approved an initial set of Reliability Standards submitted by NERC, including initial versions of four protection system and load-shedding-related maintenance standards: PRC-005-1, PRC-008-0, PRC-011-0, and PRC-017-0.[6] In addition, the Commission directed NERC to develop a revision to PRC-005-1 incorporating a maximum time interval during which to conduct maintenance and testing of protection systems, and to consider combining into one standard the various maintenance and testing requirements for all of the maintenance and testing-related standards for protection systems, underfrequency load shedding (UFLS) equipment and undervoltage load shedding (UVLS) equipment.

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[3] 16 U.S.C. at 824o(c) and (d).

[4] *See id.* at 824o(e).

[5] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g & compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[6] *Mandatory Reliability Standards for the Bulk Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, at PP 1474, 1492, 1497, and 1514, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

4. In February 2012, the Commission issued Order No. 758 in response to NERC's request for approval of its interpretation of Requirement R1 of the then-current version of the protection system maintenance standard, Reliability Standard PRC-005-1. In that order, the Commission accepted NERC's proposed interpretation of Requirement R1, which interpretation provided guidance on the types of protection system equipment to which the Reliability Standard did or did not apply. In reviewing NERC's interpretation, the Commission raised several concerns about potential gaps in the coverage of PRC-005-1, including a concern that the standard as written may not include all components that serve in some protective capacity.[7]

B. NERC Petition and Proposed Standard PRC-005-4

5. On December 18, 2014, NERC submitted a petition seeking approval of proposed Reliability Standard PRC-005-4, which would add to the applicability of Reliability Standard PRC-005-3 those sudden pressure relays that NERC has identified as having a potential effect on the reliable operation of the Bulk-Power System.[8] NERC states that

[7] *See* Order No. 758, 138 FERC ¶ 61,094 at P 12. NERC has addressed the Commission's concerns stated in Order No. 758 through a series of projects modifying the PRC-005 standard. *See Protection System Maintenance Reliability Standard*, Order No. 793, 145 FERC ¶ 61,253 (2013) (approving Reliability Standard PRC-005-2, which incorporated specific minimum maintenance activities and maximum time intervals for maintenance of individual components of the protection systems and load shedding equipment affecting the bulk electric system); *Protection System Maintenance Reliability Standard*, Order No. 803,150 FERC ¶ 61,039 (2015) (approving PRC-005-3 and directing NERC to develop a modification to include maintenance and testing of supervisory relays associated with relevant autoreclosing relay schemes).

[8] Proposed Reliability Standard PRC-005-4 is not attached to the NOPR; however, the complete text of the proposed Reliability Standard is available on the Commission's

these revisions were developed to satisfy NERC's commitment to develop modifications to PRC-005 that would address the Commission's concerns, as set out in Order No. 758, regarding the lack of maintenance requirements for non-electrical sensing relays (such as sudden pressure relays) that could affect the reliable operation of the Bulk-Power System.[9]

6. NERC states that sudden pressure relays "are designed to quickly detect faults on the Bulk-Power System transformer equipment that may remain undetected by other Protection Systems, and can operate to limit any potential damage on the equipment."[10] NERC states that the "misoperation of sudden pressure relays that initiate tripping in response to fault conditions can impact the reliability of the Bulk-Power System," and accordingly proposes revisions to PRC-005-3 that will require entities to document and implement programs for maintenance of applicable sudden pressure relays.[11]

7. NERC explains that, consistent with Order No. 758, NERC's System Protection and Control Subcommittee (SPCS) performed a technical study "to determine which devices that respond to non-electrical quantities should be addressed within PRC-005

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eLibrary document retrieval system in Docket No. RM15-9-000 and is posted on NERC's web site, *available at*: http://www.nerc.com.

[9] *See* NERC Petition at 3, 9.

[10] *Id.* at 3. NERC describes sudden pressure relays as relays which "respond to changes in pressure and are utilized as protective devices for power transformers," and which may "detect rapid changes in gas pressure, oil pressure, or oil flow that are indicative of faults within the transformer equipment." *Id* at 13. NERC notes that in addition to detecting faults, certain sudden pressure relays can trip the associated transformer circuitry in response to the fault conditions.

[11] *Id.* at 3-4.

identified devices."[12] NERC states that the SPCS considered a broad range of devices that respond to non-electrical quantities, starting with the list of ninety-four devices included in the IEEE Standard Electrical Power System Device Function Numbers, then applying "multiple layers of analysis to each device to select the ones that can affect the reliability of the Bulk-Power System."[13] The SPCS first determined that only those devices that initiate action to clear faults or mitigate abnormal system conditions presented a risk to the Bulk-Power System. Next, the SPCS eliminated those devices that were "previously considered as a result of the revised definition of Protection System or those that are clearly not protective devices, such as primary equipment and control devices."[14] Finally, the SPCS conducted an in-depth analysis of the remaining devices, and concluded that only one category – sudden pressure relays that are utilized in a trip application – should be included in the revised PRC-005-4.

8. NERC also explains that the SPCS developed a Supplemental Report in response to comments and questions about its initial recommendations from the Commission staff. These comments and questions focused on whether PRC-005 should include turbine generator vibration monitors and circuit breaker arc extinguishing systems.[15] The SPCS

[12] *Id* at 4.

[13] *Id.* at 10.

[14] *Id.*

[15] NERC Petition at 11, Ex. E, *Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities: Supplemental Information to Support Project 2007-17.3: Protection System Maintenance and Testing*, NERC SPCS (Oct. 31, 2014) (SPCS Supplemental Report).

Supplemental Report, issued on October 31, 2014, examined these two kinds of devices and provided information on events during which these devices operated or failed to operate. The Supplemental Report concluded that neither device affected the reliable operation of the Bulk-Power System.

9. NERC states that the standard drafting team that was tasked with developing the modifications to PRC-005 in response to Order No. 758 adopted the SPCS Report's recommendations, both as to the scope of additional relays included, and as to the required minimum maintenance activities and maximum maintenance intervals for these relays.

10. NERC maintains that proposed Reliability Standard PRC-005-4 will enhance reliability by extending the coverage of an applicable entity's protection system maintenance program to include sudden pressure relaying components. NERC further maintains that the proposed standard satisfies the Commission's concerns as raised in Order No. 758 "by including . . . sudden pressure relays that detect [a] fault on Bulk-Power System transformer equipment and trip in response to fault conditions, as recommended by the SPCS Report."[16]

11. NERC explains that proposed Reliability Standard PRC-005-4 has been modified to include a new definition for "Sudden Pressure Relaying,", as well as four revised

[16] NERC Petition at 12.

definitions as part of an applicable entity's protection system maintenance program.[17] NERC further explains that the proposed standard would include a sudden pressure relay that trips an interrupting device to isolate the equipment it is monitoring, but "does not include other non-electric sensing devices, pressure relays that only initiate an alarm, or pressure relief devices."[18] In addition, NERC explains that the revised standard replaces the term "Special Protection System" with the term "Remedial Action Scheme," to align the standard with NERC's employment of the latter term moving forward, and revises Applicability section 4.2.6.1 to address how the largest BES generating unit would be determined in circumstances involving a Reserve Sharing Group.

12. NERC's proposed implementation plan for PRC-005-4 incorporates the phased-in implementation period approved for PRC-005-2, which has a twelve year phase-in period, with the addition of compliance dates for the new requirements for applicable sudden pressure relays. NERC asks that PRC-005-4 become effective the first day of the first calendar quarter following Commission approval. Reliability Standard PRC-005-3 would be retired immediately prior to PRC-005-4 becoming effective.

13. NERC explains that the evidence retention period for PRC-005-4 is shorter than that required in the preceding versions of the standard, as it requires entities to maintain records for one maintenance cycle, rather than two cycles, if the interval of the

[17] NERC proposes to modify the definitions of Protection System Maintenance Program, Component Type, Component, and Countable Event to reflect the addition of sudden pressure relays to the scope of a required maintenance program. NERC Petition at 15-16.

[18] *Id.* at 18.

maintenance activity is longer than the audit cycle. For maintenance activities where the interval is shorter than the audit cycle, documentation is to be retained for all maintenance activities since the previous audit.

14. NERC states that the violation risk factors proposed in PRC-005-4 track those in previous versions of the standard, and that the violation severity levels have been revised to include the additional component (sudden pressure relays) in a manner consistent with the approach taken for PRC-005-3.

II. Discussion

15. Pursuant to section 215(d)(2) of the FPA, the Commission proposes to approve Reliability Standard PRC-005-4, as well as the new definition of Sudden Pressure Relaying, the four revised definitions referenced in the proposed standard, the assigned violation risk factors and violation severity levels, and the proposed implementation plan. We believe that proposed Reliability Standard PRC-005-4 will enhance reliability by requiring the inclusion of sudden pressure relays of certain criteria that are utilized in a trip application as part of the protection system maintenance program, and by requiring entities to undertake minimum required maintenance activities at maximum defined maintenance intervals.

16. NERC has relied on the SPCS's determination that the only non-electrical sensing devices that can impact reliable operation of the Bulk-Power System are the sudden pressure relays that can detect rapid changes in gas pressure, oil pressure, or oil flow that are indicative of faults within the transformer equipment, and can trip associated transformer circuitry to isolate the transformer and limit the potential damage of the

equipment. We agree that these relays should be included in an adequate protection system maintenance program.

17. However, we continue to have some concern that the misoperation of other types of non-electrical sensing relays or devices, such as pressure sensing devices associated with air blast or SF6 circuit breaker arc extinguishing systems, could affect the reliable operation of the Bulk-Power System. These non-electrical sensing devices are utilized in this context to give an indication that the circuit breaker may be unable to operate as designed on the Bulk-Power System. With regard to these types of devices, the SPCS stated that, "there is no operating experience in which misoperation of a density switch or sensor [i.e., pressure sensing device] in response to a system disturbance has contributed to a cascading event."[19] However, we expect Commission staff to continue exploring this issue with NERC, particularly in light of the findings in NERC's 2014 and 2013 State of Reliability reports that AC substation equipment failures remain among the leading causes of Bulk Power System problems.

III. Information Collection Statement

18. The following collection of information contained in this Notice of Proposed Rulemaking is subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995 (PRA).[20] OMB's regulations require approval of certain information collection requirements imposed by agency

[19] SPCS Supplemental Report at 4.

[20] 44 U.S.C. 3507(d) (2006).

rules.[21] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

19. We solicit comments on the Commission's need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques. Specifically, the Commission asks that any revised burden or cost estimates submitted by commenters be supported by sufficient detail to understand how the estimates are generated.

20. The Commission proposes to approve Reliability Standard PRC-005-4, which will replace PRC-005-3 (Protection System and Automatic Reclosing Maintenance). The proposed Reliability Standard expands the existing standard to cover sudden pressure relays that meet certain criteria, thereby imposing mandatory minimum maintenance activities and maximum maintenance intervals for the applicable relays. Because the specific requirements were designed to reflect common industry practice, entities are not expected to experience a meaningful change in actual maintenance and documentation practices. However, each applicable entity will have to perform a one-time review of sudden pressure relays that detect rapid changes in gas pressure, oil pressure, or oil flow

[21] 5 CFR 1320.11 (2012).

that are indicative of faults within transformer equipment, and, if it has applicable sudden pressure relay devices, review current maintenance programs to ensure that they meet the requirements of proposed standard PRC-005-4. Accordingly, all additional information collection costs are expected to be limited to the first year of implementation of the revised standard.

21. Proposed Reliability Standard PRC-005-4 reduces the evidence retention requirements approved in previously-approved versions of the standard, and now requires entities to maintain documentation of maintenance activities for only one maintenance cycle (a maximum of twelve years) if the maintenance interval is longer than the audit cycle. For maintenance activities where the interval is shorter than the audit cycle, documentation is to be retained for all maintenance activities since the previous audit. While the potential data retention requirement exceeds the three-year period that is routinely allowed for regulations requiring record retention under the OMB regulations implementing the PRA,[22] the maximum evidence retention period has been reduced from 24 years to a maximum of 12 years as a result of the Commission's prior request for comment on the reasonableness of the evidence retention period in earlier versions of the standard, and appears to reflect the minimum time needed to ensure compliance with maintenance requirements.[23]

[22] *See* 5 CFR 1320.5(d)(2)(iv).

[23] *See* Order No. 803, 150 FERC ¶ 61,039 at PP 37-38.

22. Public Reporting Burden: Affected entities must perform a one-time review of their existing sudden pressure relay schemes and associated maintenance programs to ensure that the programs contain at a minimum the activities required by Reliability Standard PRC-005-4. If the existing maintenance program does not meet the criteria in Reliability Standard PRC-005-4, the entity will have to make certain adjustments to the program.

23. Our estimate below assumes that the number of unique applicable entities (distribution providers, generator owners and transmission owners, or a combination of those) in the United States is approximately 1,287[24] and the time required to do the one-time review will be approximately eight hours. The estimate further assumes that the one-time review would be performed by an engineer at a rate of $65.34 per hour.[25]

RM15-9-000 (Mandatory Reliability Standards: Reliability Standard PRC-005-4)						
	Number of Respondents (1)	**Annual Number of Responses per Respondent (2)**	**Total Number of Responses (1)*(2)=(3)**	**Average Burden (Hours) & Cost Per Response (4)**	**Total Annual Burden Hours & Total Annual Cost (3)*(4)=(5)**	**Cost per Respondent ($) (5)÷(1)**
One-time review of sudden pressure relay maintenance program and adjustment	1,287	1	1,287	8 $523	10,296 $673,101	$523

[24] This figure reflects the generator owners, transmission owners, and distribution providers identified in the NERC Compliance Registry as of February 27, 2015.

[25] The figure is taken from the Bureau of Labor Statistics at http://www.bls.gov/oes/current/naics2_22.htm; Occupation Code: 17-2071).

Title: FERC-725P1,[26] Mandatory Reliability Standards: Reliability Standard PRC-005-4

Action: Proposed Collection of Information

OMB Control No: To be determined

Respondents: Business or other for-profit and not-for-profit institutions.

Frequency of Responses: One time.

Necessity of the Information: The proposed Reliability Standard PRC-005-4, if adopted, would implement the Congressional mandate of the Energy Policy Act of 2005 to develop mandatory and enforceable Reliability Standards to better ensure the reliability of the nation's Bulk-Power System. Specifically, the proposal would ensure that transmission and generation protection systems affecting the reliability of the bulk electric system are maintained and tested.

24. Internal review: The Commission has reviewed revised Reliability Standard PRC-005-4 and made a determination that approval of this standard is necessary to implement section 215 of the FPA. The Commission has assured itself, by means of its internal review, that there is specific, objective support for the burden estimates associated with the information requirements.

25. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, Office of the Executive Director,

[26] The FERC-725P1 is a temporary collection established so the Commission can submit this proposed rulemaking to OMB on time. However, the burden contained in this rulemaking should be contained in FERC-725G (OMB Control No. 1902-0252). Commission staff plans eventually to move this burden to FERC-725G.

888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, e-mail: DataClearance@ferc.gov, phone: (202) 502-8663, fax: (202) 273-0873].

26. Comments concerning the information collections proposed in this NOPR and the associated burden estimates should be sent to the Commission in this docket and may also be sent to the Office of Management and Budget, Office of Information and Regulatory Affairs [Attention: Desk Officer for the Federal Energy Regulatory Commission]. For security reasons, comments should be sent by e-mail to OMB at the following e-mail address: oira_submission@omb.eop.gov. Please reference the docket number of this Notice of Proposed Rulemaking (Docket No. RM15-9-000) in your submission.

IV. Regulatory Flexibility Act Analysis

27. The Regulatory Flexibility Act of 1980 (RFA)[27] generally requires a description and analysis of Proposed Rules that will have significant economic impact on a substantial number of small entities. Proposed Reliability Standard PRC-005-4 is expected to impose an additional, one-time burden on 1,287 entities (distribution providers, generator owners, and transmission owners, or a combination thereof). Comparison of the applicable entities with FERC's small business data indicates that

[27] 5 U.S.C. 601-12. The number of small distribution providers required to comply with PRC-005-4 may decrease significantly. In March 2015, the Commission approved revisions to the NERC Rules of Procedure to implement NERC's "risk based registration" program, which raised the registry threshold for distribution providers from a 25 MW to 75 MW peak load. *North American Electric Reliability Corp.*, 150 FERC ¶ 61,213 (2015).

approximately 789 of the 1,287 entities are small entities, or 61.31 percent of the respondents affected by this proposed Reliability Standard.[28]

28. On average, each small entity affected may have a one-time cost of $523, representing a one-time review of the program for each entity, consisting of 8 man-hours at $65.34/hour, as explained above in the information collection statement. We do not consider this cost to be a significant economic impact for small entities. Accordingly, the Commission certifies that proposed Reliability Standard PRC-005-4 will not have a significant economic impact on a substantial number of small entities. The Commission seeks comment on this certification.

V. Environmental Analysis

29. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[29] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do

[28] The Small Business Administration sets the threshold for what constitutes a small business. Public utilities may fall under one of several different categories, each with a size threshold based on the company's number of employees, including affiliates, the parent company, and subsidiaries. For the analysis in this NOPR, we are using a 500 employee threshold for each affected entity. Each entity is classified as Electric Bulk Power Transmission and Control (NAICS code 221121).

[29] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987).

not substantially change the effect of the regulations being amended.[30] The actions proposed herein fall within this categorical exclusion in the Commission's regulations.

VI. Comment Procedures

30. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due [**INSERT DATE 60 days after publication in the FEDERAL REGISTER**]. Comments must refer to Docket No. RM15-9-000, and must include the commenter's name, the organization they represent, if applicable, and address.

31. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

32. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

33. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section

[30] 18 CFR 380.4(a)(2)(ii).

below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VII. Document Availability

34. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

35. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number of this document excluding the last three digits in the docket number field.

36. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at 202-502-6652 (toll free at 1-866-208-3676) or e-mail at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

By direction of the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

SUNSHINE ACT MEETING NOTICE

April 9, 2015

The following notice of meeting is published pursuant to section 3(a) of the government in the Sunshine Act (Pub. L. No. 94-409), 5 U.S.C. 552b:

AGENCY HOLDING MEETING:	FEDERAL ENERGY REGULATORY COMMISSION
DATE AND TIME:	April 16, 2015 10:00 A.M.
PLACE:	Room 2C 888 First Street, N.E. Washington, D.C. 20426
STATUS:	OPEN
MATTERS TO BE CONSIDERED:	Agenda * NOTE - Items listed on the agenda may be deleted without further notice.
CONTACT PERSON FOR MORE INFORMATION:	Kimberly D. Bose Secretary Telephone (202) 502-8400 For a recorded message listing items struck from or added to the meeting, call (202) 502-8627.

This is a list of matters to be considered by the Commission. It does not include a listing of all documents relevant to the items on the agenda. All public documents, however, may be viewed on line at the Commission's website at http://www.ferc.gov using the eLibrary link, or may be examined in the Commission's Public Reference Room.

1016TH - MEETING

REGULAR MEETING

April 16, 2015

10:00 AM

Item No	Docket No.	Company
		ADMINISTRATIVE
A-1	AD02-1-000	Agency Business Matters
A-2	AD02-7-000	Customer Matters, Reliability, Security and Market Operations
A-3	AD15-12-000	Transmission Investment Metrics
		ELECTRIC
E-1	RM14-13-000	Communications Reliability Standards
E-2	AD15-11-000	Electronic Filing Protocols for Commission Forms
E-3	RM14-10-000	Real Power Balancing Control Performance Reliability Standard
E-4	RM05-5-024	Standards for Business Practices and Communication Protocols for Public Utilities
E-5	RM15-9-000	Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance Reliability Standard
E-6	RM15-4-000	Disturbance Monitoring and Reporting Requirements Reliability Standard
E-7	AD15-6-000	Grand River Dam Authority
E-8	ER15-418-001	New England Power Company
E-9	OMITTED	
E-10	OMITTED	
E-11	QM15-1-000	Virginia Electric and Power Company
E-12	ER15-910-000	Consumers Energy Company
E-13	ER15-976-000	Wolverine Power Supply Cooperative, Inc.

E-14	OMITTED	
E-15	ER12-91-008 ER12-92-008	PJM Interconnection, L.L.C., Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.
E-16	EL15-30-000	San Francisco Bay Area Rapid Transit District v. Pacific Gas and Electric Company
E-17	ER13-102-005 ER13-102-006	New York Independent System Operator, Inc.
E-18	EC12-15-001	Michigan Electric Transmission Company, LLC
E-19	EL11-42-001	Astoria Generating Company L.P. NRG Power Marketing LLC Arthur Kill Power, LLC Astoria Gas Turbine Power LLC Dunkirk Power LLC Huntley Power LLC Oswego Harbor Power LLC and TC Ravenswood, LLC v. New York Independent System Operator, Inc.
	ER12-2414-000 ER12-2414-001 ER12-2414-002	New York Independent System Operator, Inc.
E-20	EL11-50-001	Astoria Generating Company L.P. and TC Ravenswood, LLC v. New York Independent System Operator, Inc.
E-21	ER13-366-004 ER13-366-005 ER13-367-002	Southwest Power Pool, Inc.

MISCELLANEOUS

M-1	RM14-2-000	Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities

GAS

G-1	PL15-1-000	Cost Recovery Mechanisms for Modernization of Natural Gas Facilities

HYDRO

H-1	P-2305-044	Sabine River Authority of Texas Sabine River Authority, State of Louisiana

CERTIFICATES

C-1	CP14-503-000	Enable Gas Transmission, LLC
C-2	CP14-87-001	Southeast Supply Header, LLC
C-3	RP14-638-000	Atmos Energy Corporation v. American Midstream (Midla), LLC
	CP14-125-000 CP14-126-000 RP14-689-000 RP14-689-001 RP14-1049-000 RP14-1049-001 RP14-1049-002 (not consolidated)	American Midstream (Midla), LLC

Kimberly D. Bose,
Secretary.

A free webcast of this event is available through www.ferc.gov. Anyone with Internet access who desires to view this event can do so by navigating to www.ferc.gov's Calendar of Events and locating this event in the Calendar. The event will contain a link to its webcast. The Capitol Connection provides technical support for the free webcasts. It also offers access to this event via television in the DC area and via phone bridge for a fee. If you have any questions, visit www.CapitolConnection.org or contact Danelle Springer or David Reininger at 703-993-3100.

Immediately following the conclusion of the Commission Meeting, a press briefing will be held in the Commission Meeting Room. Members of the public may view this briefing in the designated overflow room. This statement is intended to notify the public that the press briefings that follow Commission meetings may now be viewed remotely at Commission headquarters, but will not be telecast through the Capitol Connection service.

April 2015
Commission Meeting Summaries

These are summaries of orders voted by the Federal Energy Regulatory Commission at its April 16, 2015 public meeting. The summaries are produced by FERC's Office of External Affairs and are intended to provide only a general synopsis of the orders. These summaries are not intended as a substitute for the Commission's official orders. To determine the specific actions and the Commission's reasoning, please consult the individual orders when they are posted to FERC's eLibrary found at www.ferc.gov.

SUPPLEMENTAL

FERC denies rehearing, conditionally accepts compliance filing

E-21, *Southwest Power Pool*, Docket No. ER13-366-004. On October 16, 2014, the Commission issued an order conditionally accepting Southwest Power Pool, Inc.'s (SPP) second filing to comply with the local and regional transmission planning and cost allocation requirements of Order No. 1000 and the Commission's First Compliance Order. The Commission accepted SPP's second compliance filing, effective March 30, 2014, subject to a further compliance. On November 17, 2014, LS Power Transmission, LLC and LSP Transmission Holdings, LLC (together, LS Power) submitted a timely request for rehearing of the Second Compliance Order. On December 15, 2014, in Docket No. ER13-366-005, SPP submitted revisions to Attachments O and Y of the SPP Open Access Transmission Tariff (Tariff) to comply with the Second Compliance Order. This order denies LS Power's request for rehearing. The order also finds that SPP's December 15, 2014 compliance filing partially complies with the directives of the Second Compliance Order. The order conditionally accepts SPP's proposed revisions to the tariff, subject to a further compliance filing within 30 days of the date of issuance of this order.

Summaries of NERC Items on FERC April 16, 2015 Open Meeting Agenda

1. Agenda Item E-1, in Docket No. RM14-13-000: *Communications Reliability Standards*

On May 14, 2014, NERC filed a petition for approval of proposed Reliability Standards COM-001-2-(Communications) and COM-002-4 (Operating Personnel Communications Protocols). Proposed Reliability Standards COM-001-2 and COM-002-4 replace and improve upon the currently effective COM-001-1.1 and COM-002-2 Reliability Standards to establish requirements for communication capabilities and communications protocols necessary to maintain reliability. Proposed COM-001-2 establishes a clear set of requirements for what communications capabilities various functional entities must maintain for reliable communications. Proposed COM-002-4 requires entities to have or create a set of documented communications protocols that include certain minimum mandatory protocols. On May 15, 2014, NERC filed an Errata to the Petition. On September 18, 2014, the Commission issued a NOPR proposing to approve the proposed Reliability Standards COM-001-2 and COM-002-4. On December 1, 2014, NERC filed comments in response to the NOPR.

2. Agenda Item E-3, in Docket No. RM14-10-000: *Real Power Balancing Control Performance Reliability Standard*

On April 2, 2014, NERC filed a petition for approval of proposed Reliability Standard BAL-001-2 (Real Power Balancing Control Performance). The proposed BAL-001-2 standard improves reliability by adding a frequency component to the measurement of a Balancing Authority's Area Control Error ("ACE") and allows for the formation of "Regulation Reserve Sharing Groups." On November 20, 2014, the Commission issued a NOPR proposing to approve the proposed Reliability Standard BAL-001-2. On January 26, 2015 NERC filed comments in response to the NOPR.

3. Agenda Item E-5, in Docket No. RM15-9-000: *Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance Reliability Standard*

On December 18, 2014 NERC filed a petition for approval of proposed Reliability Standard PRC-005-4 (Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance). The purpose of the proposed PRC-005-4 standard is to document and implement programs for the maintenance of all Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying affecting the reliability of the Bulk Electric System so that they are kept in working order.

4. Agenda Item E-6, in Docket No. RM15-4-000: *Disturbance Monitoring and Reporting Requirements Reliability Standard*

On December 15, 2014, NERC filed a petition for approval of proposed Reliability Standard PRC-002-2 (Disturbance Monitoring and Reporting Requirements). The proposed PRC-002-2 standard focuses on ensuring that the requisite data is captured and the Requirements constitute a results-based approach to capturing data.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Lesson Learned

Importance of Backup Energy Management System Failover Testing after Network Device Reconfiguration

Primary Interest Groups
Reliability Coordinators (RCs)
Transmission Operators (TOPs)
Transmission Owners (TOs)

Problem Statement
There was a loss of energy management system (EMS) supervisory control and data acquisition (SCADA) functionality for 49 minutes during a scheduled transfer of the EMS from the alternate control center (ACC) to the primary control center (PCC).

Details
Prior to performing maintenance on the PCC's uninterruptable power supply (UPS), all functionality of the EMS system, including the communication circuits, was successfully transferred from the PCC to the ACC. Upon completion of this maintenance work, the EMS communication circuit vendor was contacted and notified of the organization's intent to request a transfer of the communication circuits from the ACC to the PCC as soon as the PCC was made functional. The vendor provided the name and phone number of the technician who would be available to perform the switching.

The EMS analysts attempted to bring system functionality back to the PCC but the attempt was unsuccessful. A full system restart was then performed to establish system functionality at the PCC. The PCC came on-line, but the ACC failed, and EMS analysts were unable to restore ACC functionality. At this moment, the EMS loss-of-functionality event commenced due to the EMS communication circuits still being connected to the failed ACC. It should be noted that an EMS loss-of-functionality event will occur every time a full system restart is performed, and the duration of a typical event is five to eight minutes.

The protracted duration of this event is due to the communication vendor's maintenance operation. Following the unsuccessful full system restart, the communication vendor was again contacted and was requested to transfer the communication circuits from the ACC to the PCC. The vendor reported that they were unable to proceed with the EMS communication circuit transfer because they were in the process of performing system maintenance. After the vendor completed this maintenance, the communication circuit transfer was successfully completed and EMS functionality was restored at the PCC. The duration of the EMS loss-of-functionality event was 49 minutes. At the event's conclusion, the ACC remained in a failed state.

Upon subsequent investigation, it was discovered that due to a recent and extensive network device reconfiguration, one of the parameters was in error, and this resulted in the inability to restore ACC

functionality via a full system restart. Device configuration modifications were then performed, and the ACC was successfully restarted with functionality restored.

Control was transferred from the PCC to the ACC due to UPS maintenance. Communication circuits were routed to the ACC.

After the completion of maintenance, the EMS analysts attempted to bring system functionality back at the PCC, but the attempt was unsuccessful.

After other attempts to correct the PCC, a full system restart was attempted. The full system restart caused EMS loss-of-functionality.

All PCC nodes were restored while all ACC nodes failed. The communication circuits were still routed to the ACC.

The communication vendor was requested to transfer communications back to the PCC, but the vendor was performing maintenance for 15 minutes and was unable to initiate a transfer.

EMS analysts initiated a second system restart but achieved the same results: all PCC nodes restored and all ACC nodes failed.

The communication vendor was contacted again to transfer the communication circuit back to the PCC.

The SCADA communication circuit transfer to the PCC was completed. The EMS loss-of-functionality event concluded.

Corrective Actions

- To minimize EMS downtime during EMS system restart operations, the existing EMS system restart checklist procedure was revised. This procedure defines all the steps necessary to perform a system restart. A flow chart was added with suggested analysis and steps to be taken when restarts do not perform as expected. Additionally, a new site isolation system was implemented to effectively separate and isolate PCC and ACC functionality.
- A procedure was developed to ensure that no planned communication vendor maintenance is performed during periods when the EMS is being transferred between the PCC and the ACC.
- The recent network device configuration modification was quite extensive, and one configuration parameter that was modified was found to be in error. This error resulted in the EMS loss-of-functionality event. It is now believed that this errant configuration parameter may have been detected if full functional failover testing was performed. As a result, testing procedures associated with reconfigurations performed on the EMS network device were reviewed and updated. The changes are rated based on the potential impact to the EMS system, and the extent of testing performed is based on this rating. All EMS analysts were retrained for these new procedures.

Lessons Learned

- EMS maintenance and reconfiguration operations should be closely coordinated with vendors that are needed to support the changes to ensure that there are no overlaps in planned maintenance schedules. Succinct and accurate communication between registered entities and vendors is

essential to ensure that both parties fully understand their roles and obligations during planned maintenance operations.

- Procedures for EMS system restart operations should be rigorously documented to ensure that the EMS can be restarted in the most rapid and secure manner. A step-by-step checklist for the procedure is desirable to ensure that no steps are overlooked. Steps should be included in the procedure to address conditions where restarts do not perform as expected.
- Entities should periodically review EMS redundancy to ensure ongoing independence between sites, including full functional failover testing.
- Entities should review and identify the extent of testing to be performed following significant EMS infrastructure reconfiguration.

NERC's goal with publishing lessons learned is to provide industry with technical and understandable information that assists them with maintaining the reliability of the bulk power system. NERC requests that you provide input on this lesson learned by taking the short survey provided in the link below.

Click here for: Lesson Learned Comment Form

For more Information please contact:

NERC – Lessons Learned (via email)	NPCC – Event Analysis
Source of Lesson Learned:	Northeast Power Coordinating Council
Lesson Learned #:	20150301
Date Published:	March 3, 2015
Category:	Communications

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Lesson Learned

Importance of State Estimator Save Cases and Troubleshooting Guide

Primary Interest Groups
Reliability Coordinators (RCs)
Transmission Operators (TOPs)
Transmission Owners (TOs)

Problem Statement
A state estimator failed to solve for 37 minutes, resulting in real-time contingency analysis also being unavailable.

Details
During this event, operators had system visibility via supervisory control and data acquisition (SCADA) and could still take control actions, including the ability to shed load.

The Inter-Control Center Communications Protocol (ICCP) continued to function, providing real-time data to the RC and the other local entities in the RC's footprint. The entity confirmed with its RC that the RC's state estimator continued to solve and provide real-time contingency analysis.

The root cause was never specifically determined. At the time of the event, the state estimator was not archiving save cases on a periodic basis. Because there was no saved data to review, support staff were unable to perform a detailed post-event analysis.

Corrective Actions

- The entity developed a method to automatically archive state estimator save cases more frequently to assist in post-event reviews.
- The entity developed a state estimator troubleshooting guide for system operators to ensure a consistent approach and performed refresher training for them.
- The entity worked with its RC and other local entities to review solution parameters that could contribute to unsolved state estimator solutions.

Lessons Learned

- A state estimator should be able to automatically and frequently save cases to assist in post-event analysis. It should also automatically save non convergent cases.
- Operators and support staff should have clear guidance and training on troubleshooting state estimator failures. An online state estimator guide for systems operators should be available to

ensure consistent troubleshooting. Periodic refresher training should also be employed, including reviews of recent aborted cases.

- A joint review of state estimator issues with other entities should be periodically conducted to ensure applicable common solutions are implemented.

NERC's goal with publishing lessons learned is to provide industry with technical and understandable information that assists them with maintaining the reliability of the bulk power system. NERC requests that you provide input on this lesson learned by taking the short survey provided in the link below.

Click here for: Lesson Learned Comment Form

For more Information please contact:

NERC – Lessons Learned (via email)	NPCC – Event Analysis
Source of Lesson Learned:	Northeast Power Coordinating Council
Lesson Learned #:	20150302
Date Published:	March 3, 2015
Category:	Communications

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

July 21, 2014

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: North American Electric Reliability Corporation
Five-Year Electric Reliability Organization Performance Assessment Report
Submitted in Accordance with 18 C.F.R. § 39.3(c)

Dear Ms. Bose:

The North American Electric Reliability Corporation (NERC) respectfully submits its Five-Year Electric Reliability Organization (ERO) Performance Assessment Report in accordance with the requirements of the Commission's regulations at 18 C.F.R. § 39.3(c).

The filing consists of this transmittal letter and the following documents:

- **Overview of NERC Activities and Accomplishments in the Five-Year Period**
- **Attachment 1:** Discussion of How NERC Meets the ERO Certification Criteria of 18 C.F.R. §39.3(b)
- **Attachment 2:** Joint Regional Entity Self-Assessment
- **Attachment 3:** NERC Assessment of Regional Entity Delegated Functions
- **Attachment 4:** NERC Consideration of Industry Feedback
- **Attachment 5:** Status of Areas for Improvement Identified in the Order on the Three-Year ERO Performance Assessment
- **Attachment 6:** NERC's Plan and Initiatives for Improving Coordinated Operations Across the ERO Enterprise

These documents are transmitted in two PDF files.

Please place the following persons on the Commission's official service list on behalf of NERC with respect to this submittal and the proceeding that we understand the Commission will open pursuant to 18 C.F.R. § 39.3(c) to consider this report:

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Please contact the undersigned if you have any questions concerning this filing.

Respectfully submitted,

/s/ Nina H. Jenkins-Johnston
Nina H. Jenkins-Johnston

Attorney for the North American Electric Reliability Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	**)** **)**	**Docket No. RR14-__-000**

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

FIVE-YEAR ELECTRIC RELIABILITY ORGANIZATION PERFORMANCE ASSESSMENT REPORT

SUBMITTED IN ACCORDANCE WITH 18 C.F.R. §39.3(c)

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July 21, 2014

FEDERAL ENERGY REGULATORY COMMISSION
DOCKET NO. RR14-___

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

FIVE-YEAR ELECTRIC RELIABILITY ORGANIZATION PERFORMANCE ASSESSMENT REPORT

OVERVIEW OF NERC ACTIVITIES AND ACCOMPLISHMENTS IN THE FIVE-YEAR PERIOD

SUBMITTED IN ACCORDANCE WITH 18 C.F.R. §39.3(c)

JULY 21, 2014

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I. INTRODUCTION

A. Contents of Five-Year ERO Performance Assessment

The North American Electric Reliability Corporation (NERC) is submitting this *Five-Year Electric Reliability Organization (ERO) Performance Assessment Report* in accordance with the Commission's regulations at 18 C.F.R. §39.3(c). NERC was certified by the Commission as the ERO, pursuant to §215(c) of the Federal Power Act (FPA), by Commission order issued July 20, 2006.[1] The Commission's regulations at 18 C.F.R. Part 39 require the ERO to submit an assessment of its performance three years from the date of certification and every five years thereafter.[2] On July 20, 2009, NERC filed its initial, Three-Year ERO Performance Assessment Report with the Commission. On September 16, 2010, the Commission issued an order accepting the three-year performance assessment of NERC and the Regional Entities and found that they continue to satisfy the statutory and regulatory criteria for certification.[3] NERC now submits this *Five-Year ERO Performance Assessment Report* in accordance with the Commission's regulations.

In this *Five-Year ERO Performance Assessment Report*, NERC describes its activities and accomplishments during the assessment period[4] in carrying out its statutory and regulatory responsibilities as the ERO, with a particular focus on the latter part of the assessment period and on NERC's current and planned initiatives. As required by 18 C.F.R. §39.3(c)(1), this report: (i) describes how NERC continues to meet the certification criteria of 18 C.F.R. §39.3(b); (ii)

[1] *Order Certifying the North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062 (2006).

[2] 18 C.F.R. §39.3(c).

[3] *Order on the Electric Reliability Organization's Three-Year Performance Assessment*, 132 FERC ¶ 61,217 (2010).

[4] NERC defines the assessment period as January 1, 2009 through May 31, 2014.

evaluates of the effectiveness of each Regional Entity in carrying out its delegated functions;[5] and (iii) addresses stakeholder comments on NERC's performance that were collected in the preparation of this report. As noted, this report identifies actions that NERC and the Regional Entities are currently taking and plan to take to continue to improve their operations to enhance the reliable operation of the bulk power system (BPS). Unlike the three-year performance assessment report, NERC has not presented a program area-by-program area discussion of activities because NERC's annual business plan and budgets (and those of the Regional Entities) provide the Commission with an annual, detailed look at NERC's and each Regional Entity's current and planned activities by program area. Instead, this *Five-Year ERO Performance Assessment Report* highlights activities and accomplishments in support of the ERO Enterprise[6] Strategic Plan (Strategic Plan) initiatives applicable to this assessment period. These initiatives include: (i) Reliability Standards reform (both as to the number and content of Reliability Standards and the processes for developing them); (ii) the Reliability Assurance Initiative (RAI) which involves identifying risks to reliability and reformulating the compliance monitoring and enforcement processes to have a risk-based focus; and (iii) the revision of the bulk electric system (BES) definition.

In this *Five-Year ERO Performance Assessment Report*, NERC also demonstrates how the ERO is improving the performance of, and mitigating risks to, the BPS as related to avoidable outages. As detailed in NERC's *State of Reliability 2014* report, the number of BPS transmission-related events resulting in loss of firm load, other than events caused by factors

[5] The eight Regional Entities are: (i) Florida Reliability Coordinating Council, Inc.; (ii) Midwest Reliability Organization; (iii) Northeast Power Coordinating Council, Inc.; (iv) ReliabilityFirst Corporation; (v) SERC Reliability Corporation; (vi) Southwest Power Pool Regional Entity; (vii) Texas Reliability Entity, Inc.; and (viii) Western Electricity Coordinating Council (WECC).

[6] NERC uses the term "ERO Enterprise" to encompass both NERC and the eight Regional Entities.

external to the transmission system's actual performance (i.e., weather-initiated events), decreased from an average of ten per year over a ten year period (2002 through 2011) to seven in 2013. The daily severity risk index value (SRI), a metric created by NERC that measures risk impact or "stress" from events resulting in the loss of transmission, generation, and load, has been stable from 2008 to 2013. Including weather-initiated events, 2013 had no high-stress days, which is within the range of zero to seven days experienced during 2008 through 2013. The availability of the bulk transmission system, as measured by the SRI and other metrics, continues to remain high with no statistically significant change from 2008 to 2013.[7]

Despite the progress made to date in improving the reliability of the BPS and reducing the risks to reliability, opportunities remain for enhancements to ensure that the BPS remains reliable. NERC describes these opportunities, and its initiatives designed to pursue them, in this *Five-Year ERO Performance Assessment Report*. Additionally, in this assessment report, NERC evaluates the effectiveness of each Regional Entity in performing its delegated functions, drawing from NERC's ongoing oversight activities, the Regional Entities' self-assessments, and feedback solicited from industry through an industry survey and posting the Regional Entity self-assessments for stakeholder comment.

Finally, NERC describes how its compliance monitoring and enforcement efforts have matured into a robust program providing industry with greater certainty on actions, outcomes, and reliability consequences. The actions taken by the ERO to identify, correct, and prevent violations of NERC's Reliability Standards have promoted the reliability of the BPS. For example, the adoption, modification, and rigorous enforcement of NERC's transmission vegetation management Reliability Standard (FAC-003), which became mandatory and

[7] NERC's *State of Reliability 2014* report is available at: http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2014_SOR_Final.pdf.

enforceable in 2007, has dramatically reduced the number of outages caused by vegetation growing into high voltage lines. From 2004 through 2008, there were 58 reported outages. By contrast, from 2009 through 2013, only six instances were reported.[8]

B. Industry Engagement

The electric industry has made tremendous strides towards improving reliability since the August 2003 Northeast blackout, which left 50 million customers without power. Enactment of §215 of the FPA, NERC's certification as the ERO, and the adoption of mandatory and enforceable Reliability Standards renewed the industry's focus on reliability. This focus, which includes proactive steps by the ERO to identify and address risks and avoid preventable events, has had a demonstrable and positive impact on reliability.

In passing the Energy Policy Act of 2005, which included the enactment of §215, Congress recognized the importance of an international ERO across North America to ensure the reliability of the BPS. As the ERO, NERC plays a unique role in facilitating industry engagement to create effective approaches for reliability initiatives. For example, industry participation in Reliability Standards development from start to finish is critical. Industry stakeholders participate in Reliability Standards development with increasing frequency since changes to the *Standard Processes Manual* (SPM) became effective June 26, 2013.[9] Stakeholders participate directly by joining standard drafting teams or participating as observers; attending and discussing Reliability Standards at webinars, committee meetings or technical conferences with standard drafting team members and NERC staff; communicating technical opinions directly to standard drafting teams or NERC staff; and commenting and voting on

[8] NERC's quarterly *Vegetation-Related Transmission Outage Reports* are available at: http://www.nerc.com/pa/comp/CE/Pages/vegetation-management-reports.aspx.

[9] The SPM is Appendix 3A to the NERC Rules of Procedure (NERC ROP) and is available at: http://www.nerc.com/pa/Stand/Documents/Appendix_3A_StandardsProcessesManual.pdf.

proposed Reliability Standards. As of May 2014, 858 stakeholder representatives had registered their eligibility to vote on proposed Reliability Standards as members of the Registered Ballot Body, and in 2013 alone NERC hosted 43 Reliability Standard industry webinars attended by an average of 360 participants. During the last six months of 2013, standard drafting teams and five-year review teams made up of 195 industry volunteers participated in 60 team meetings to advance standard development activities.[10]

Industry engagement is also a critical component of NERC's strategic initiatives, such as RAI. Through RAI, NERC and the Regional Entities are adopting a risk-based approach to compliance monitoring and enforcement activities.[11] NERC and the Regional Entities are spearheading RAI, with substantial input from industry representatives on important RAI projects. For example, the ERO Enterprise is examining information flow requirements for registered entity self-reporting and is developing criteria to evaluate the various approaches to reliability risk assessments and internal controls review and testing. Similarly, industry played an important role in the development and implementation of NERC's Find, Fix, Track and Report (FFT) process, an enforcement mechanism that differentiates and processes noncompliance occurrences according to their significance to the reliability of the BPS.

Preparation of this *Five-Year ERO Performance Assessment Report* has benefited from considerable input from industry. On October 31, 2013, NERC distributed a 36-question online survey soliciting numerical ratings and free-form responses from registered entities regarding the performance of NERC and the Regional Entities in carrying out their responsibilities. On March 3, 2014, NERC posted a draft statement of its activities and accomplishments, as well as drafts of

[10] As described later in this *Overview of NERC Activities and Accomplishments in the Five-Year Period*, five-year review teams are engaged in the five-year reviews of those Reliability Standards that have been adopted by the American National Standards Institute (ANSI) as national standards, in accordance with §13.0 of the SPM.

[11] NERC expects to submit an informational filing in 2014 fully describing RAI.

the Regional Entities' self-assessments, on NERC's website for industry comment. On June 17, 2014, NERC posted a complete draft of the *Five-Year ERO Performance Assessment Report* on its website for stakeholder comment. A compilation of the responses to the survey questions and of the comments received on the March 3, 2014 and June 17, 2014 postings, are included as **Attachment 4** to this report.[12]

This *Five-Year ERO Performance Assessment Report* includes the following attachments:

Attachment 1: Discussion of How NERC Meets the ERO Certification Criteria of 18 C.F.R. §39.3(b)

Attachment 2: Joint Regional Entity Self-Assessment[13]

Attachment 3: NERC Assessment of the Regional Entities' Delegated Functions

Attachment 4: NERC Consideration of Industry Feedback

Attachment 5: Status of Areas for Improvement Identified in the Order on the Three-Year ERO Performance Assessment

Attachment 6: NERC's Plan and Initiatives for Improving Coordinated Operations Across the ERO Enterprise

NERC requests that the Commission accept this filing as satisfying NERC's obligation under 18 C.F.R. §39.3(c) to file a performance assessment every five years after the three-year anniversary of its certification as the ERO. Pursuant to 18 C.F.R. §39.3(c), the Commission will initiate a proceeding, with opportunity for public comment, on NERC's *Five-Year ERO Performance Assessment Report*. At the conclusion of the proceeding, the Commission will either issue an order finding that NERC and the Regional Entities meet the statutory and regulatory criteria, or direct them to come into or improve their compliance with

[12] Issues raised by stakeholders, and the responses of NERC and the Regional Entities, are addressed in this report. Industry responses to the survey were discussed at the February 28, 2014 NERC Member Representatives Committee (MRC) meeting, and industry responses to the survey and comments received on the March 3, 2014 posting were discussed at the May 6, 2014 NERC Board of Trustees (NERC Board) meeting.

[13] **Attachment 2** contains both an overall self-assessment of the Regional Entities' collective performance during the assessment period, and individual discussions of how each Regional Entity satisfied the applicable statutory and regulatory criteria including those specified in the Commission's regulations at 18 C.F.R. §39.8.

the requirements of Part 39. Because considerable opportunity has been provided for stakeholder input through the industry survey and the posting of drafts of this report, NERC suggests that the Commission initiate its proceeding by setting a comment period of no more than 45 days on the filed report. Conducting the Commission's proceeding pursuant to §39.3(c) in an expeditious manner will allow NERC and the Regional Entities both to receive timely feedback from commenters and the Commission and to move forward and devote time and resources to the various initiatives outlined in the report. NERC will use the contents of this *Five-Year ERO Performance Assessment Report* and the results of the proceeding to guide the continuing implementation and evolution of its programs in the years ahead.

II. NERC ACTIVITIES AND ACCOMPLISHMENTS

This section describes activities and initiatives that NERC has completed during the assessment period, has in progress, or plans to commence in the near future, to enhance the reliability of the BPS and to increase the effectiveness and efficiency of the operations of the ERO Enterprise. NERC focuses this discussion on the following five areas: (i) development of clear, reasonable and technically sound Reliability Standards; (ii) registration of entities with functional responsibilities for the reliability of the BPS; (iii) monitoring and enforcing compliance with Reliability Standards; (iv) identification, prioritization and dissemination of information on risks to the reliability of the BPS; and (v) collecting and sharing information on cybersecurity and threats to the cyber and physical security of the BPS.

A. The ERO Is Transitioning NERC Reliability Standards to a Steady-State

Since the three-year performance assessment, NERC has made great strides in transforming Reliability Standards to a steady-state, which NERC defines as a stable set of clear, concise, high-quality, and technically sound Reliability Standards. Steady-state Reliability Standards are results-based and include requirements that promote reliability. They are

sustainable (stable), necessary for accountability, and sufficient to maintain the reliability of the BPS. After a set of steady-state Reliability Standards is fully developed, it is expected that Reliability Standards will only need to be amended in response to changes in risks, technology, practices, and similar changes. In support of this objective, during the assessment period, NERC focused on addressing FERC directives and conducting periodic reviews of Reliability Standards. NERC expects to complete the development of a set of steady-state Reliability Standards in 2015.

NERC's efforts to arrive at steady-state Reliability Standards would not have been possible without strong participation from industry stakeholders, FERC staff, the NERC Standards Committee (SC), and other NERC committees and working groups, including the Reliability Issues Steering Committee (RISC) and the Standards Process Improvement Group (SPIG), the NERC Board, and the NERC MRC. Arriving at a set of steady-state Reliability Standards required changes in NERC's Reliability Standards development process. The SPIG identified needed changes to the process. These changes were implemented through amendments to the SPM that became effective on June 26, 2013, upon Commission approval.[14]

The currently effective *Reliability Standards Development Plan 2014-2016* (RSDP), approved by the NERC Board in November 2013, endorses the objective of arriving at steady-state Reliability Standards.[15] It specifically defines "steady-state" as a stable set of clear, concise, high quality, and technically sound Reliability Standards that are results-based and that exclude requirements that do little to promote reliability. The 2014-2016 RSDP prioritizes future Reliability Standards projects as high, medium, low or pending technical committee input based

[14] *Order Approving Revisions to Electric Reliability Organization's Standard Processes Manual*, 143 FERC ¶ 61,273 (2013).

[15] *Reliability Standards Development Plan 2014-2016* is available at: http://www.nerc.com/pa/Stand/Pages/ReliabilityStandardsDevelopmentPlan.aspx.

on a series of inputs, which include the Standards Independent Expert Review Panel's (IERP or Panel) content and quality assessments (discussed later in this document). Prioritization considerations were influenced by: (i) RISC category rankings (also described later in this document); (ii) outstanding regulatory directives; (iii) regulatory deadlines; (iv) Paragraph 81 retirement candidates (also described below); (v) content and quality assessments by the IERP (also described below); and (vi) additional considerations such as fill-in-the-blank status and five-year review assessment commitments.

During the assessment period, NERC launched several initiatives to improve Reliability Standards, including: (i) the results-based Reliability Standards initiative; (ii) the Paragraph 81 project; (iii) the reorganization of the Reliability Standards department; and (iv) the establishment of the IERP. Each of these initiatives built upon the prior initiative, resulting in a comprehensive set of criteria by which to evaluate whether a Reliability Standard has reached its steady-state.

Since the three-year performance assessment, NERC initiated the results-based concept for developing the content of Reliability Standards. Each requirement of a results-based Reliability Standard identifies a measurable outcome such as: (i) a stated level of reliability performance; (ii) a reduction in a specified reliability risk (prevention); or (iii) a necessary competency. In 2011, NERC began training standard drafting teams to write results-based Reliability Standards. In 2013, the Commission approved the first Reliability Standard that resulted from that effort, FAC-003-2 – Transmission Vegetation Management.[16] NERC is in the process of converting major families of Reliability Standards into results-based Reliability

[16] *Revisions to Reliability Standard for Transmission Vegetation Management*, 142 FERC ¶ 61,208 (2013).

Standards.[17] These Reliability Standards include those dealing with long-term planning, reliability coordination, and real-time operations.[18]

In 2012, in response to FERC's invitation to NERC in a March 15, 2012 Order, NERC and industry conducted the Paragraph 81 project, which identified and retired requirements from Reliability Standards that did little to support reliability.[19] The criteria developed to scrutinize existing requirements in Reliability Standards in response to the Commission's Paragraph 81 invitation continue to be used by standard drafting teams to evaluate the need for proposed requirements in new Reliability Standards development projects.[20]

In further support of the development of steady-state Reliability Standards, NERC reorganized its Standards department in 2013 to focus resources on addressing FERC directives, conducting periodic reviews of Reliability Standards, and completing ongoing Reliability Standards development projects. NERC also conducted a parallel effort to identify future work necessary to transform the Reliability Standards to steady-state, by establishing the IERP to evaluate the content and quality of every requirement in the NERC Reliability Standards. The Panel established its own criteria, which included those developed in the Paragraph 81 project, to

[17] The terms "families of standards" refers to groupings of Reliability Standards that address a common subject matter area, e.g., Emergency Preparedness and Operations (EOP), Personnel Performance, Training and Qualifications (PER), and Protection and Controls (PRC).

[18] NERC revised the Transmission Planning (TPL) Reliability Standards and a single consolidated Reliability Standard approved by FERC; revisions to the Transmission Operations (TOP), Interconnection Reliability Operations and Coordination (IRO), Modeling (MOD), and Voltage and Reactive (VAR) standards are pending FERC approval.

[19] "Paragraph 81" refers to P 81 of the Commission's March 15, 2012 Order on NERC's FFT process, in which the Commission invited NERC (as well as the Regional Entities and other stakeholders) to identify specific standards requirements that could be revised or removed because they provide little protection for BPS reliability or are redundant. *Order Accepting with Conditions the Electric Reliability Organization's Petition Requesting Approval of New Enforcement Mechanisms and Requiring Compliance Filing*, 138 FERC ¶ 61,193 (2012) (March 2012 FFT Order), at P 81. *See* §II.A.3 below for a more detailed description of the Paragraph 81 initiative.

[20] The Paragraph 81 criteria are outlined in the Phase I *Paragraph 81 Project Technical White Paper* available at: http://www.nerc.com/pa/Stand/Project%20201302%20Paragraph%2081%20RF/P81_Phase_I_technical_white_paper_FINAL.pdf.

determine whether a requirement was steady-state or needed further revisions. The Panel's recommendations set the course for arriving at high quality, results-based Reliability Standards with sustainable requirements. NERC is preparing training materials for standard drafting teams to highlight the use of the Panel's methods for content and quality assessments of Reliability Standards.

NERC has also been diligent in assessing the need for Reliability Standards that address reliability gaps. Sections II.A.8.a through e below discuss five important areas of Reliability Standards development focusing on reliability risk: (i) the Critical Infrastructure Protection (CIP) Version 5 Reliability Standards; (ii) vegetation management (formerly a top ten cause of outage events); (iii) protection system maintenance and testing; (iv) geomagnetic disturbances (GMD) (a high-impact, low-frequency risk to the BPS which does not readily manifest in reliability performance data, but nonetheless represents a significant risk to the BPS); and (v) the physical security Reliability Standard.

A more recent initiative to assist with the achievement of steady-state Reliability Standards is the development of a template for enhanced periodic reviews of Reliability Standards that have not yet been revised through other Reliability Standards development projects. NERC is working with industry stakeholders to develop the necessary criteria for determining which Reliability Standards will be subject to these enhanced periodic reviews as well as whether the Reliability Standards have reached their steady-state. NERC expects the criteria to include those from the results-based Reliability Standards initiative, the Paragraph 81 project and the IERP. Upon reaching a consensus with industry on the criteria for evaluating whether a requirement is steady-state, and after completing the projects identified in the ERO's 2014-2016 RSDP and the ERO's 2015-2017 RSDP, NERC will apply the criteria to the

Reliability Standards through enhanced periodic reviews beginning in 2015.[21]

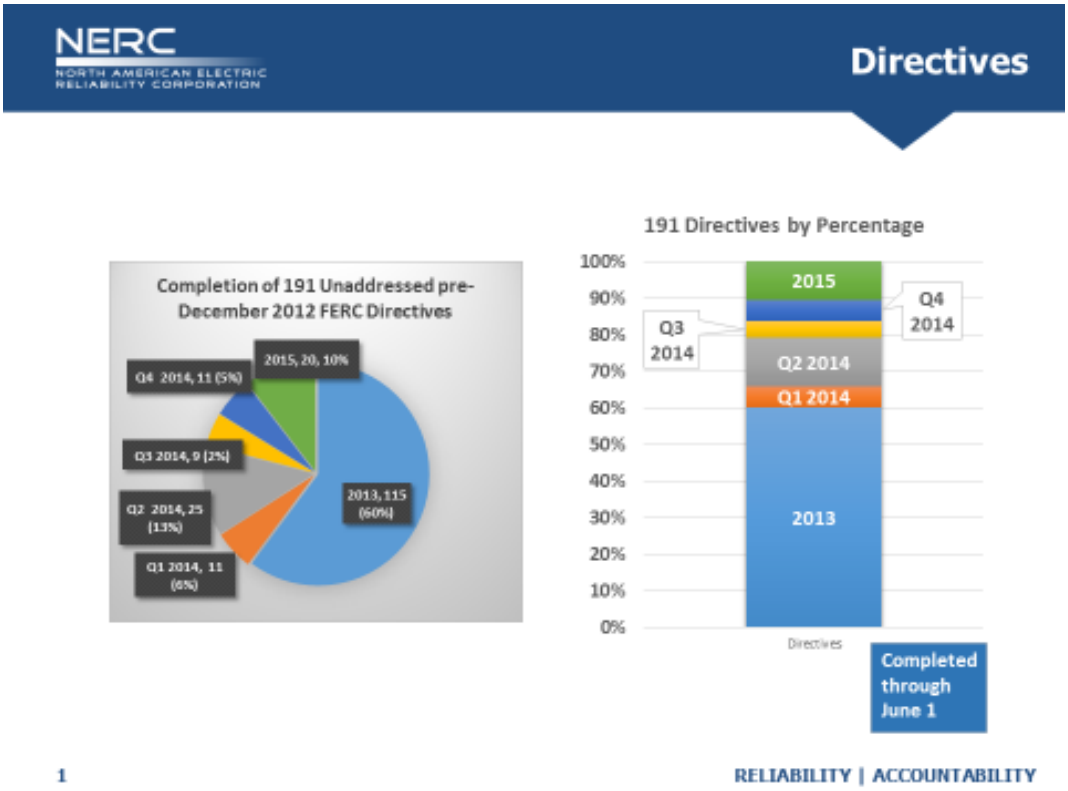
1. Completing Commission Directives

During this assessment period, NERC made significant progress in reducing the number of Commission directives involving Reliability Standards. Addressing these directives is a priority to facilitate the transformation to steady-state.[22] The status of NERC's efforts in addressing Reliability Standards-related directives is reported on a quarterly basis to the NERC Standards Oversight and Technology Committee (SOTC). At the February 2014 SOTC meeting, NERC reported that 128 directives had been addressed by year-end 2013, with 107 directives remaining to be addressed. NERC continues to report the status of completion at every SOTC meeting and anticipates that 90% of FERC directives issued to date will be resolved during the first half of 2015.

[21] The 2014-2016 RSDP identified 18 Reliability Standard development projects completed in 2013 or scheduled to be completed by the first quarter of 2014. It also identified 13 projects that were to be completed thereafter.

On June 20, 2014, the draft 2015-2017 RSDP was posted for industry comment. Currently, it identifies 27 projects that have been completed or are in progress, many of which were newly introduced in 2014. Eight of these 27 projects have been approved by the Registered Ballot Body, approved by the NERC Board, and filed with FERC for approval, and 12 are anticipated to be completed in 2014. The draft 2015-2017 RSDP identifies the remaining seven projects that will extend into 2015, with completion anticipated in the first half of the year. Additionally, four new projects for 2015 are identified. Completion of these projects will position NERC to begin enhanced periodic reviews in late 2015.

[22] Directives may be addressed by: (i) completing the directive as assigned; (ii) addressing the reliability concern of the directive in an equally effective and efficient manner; or (iii) providing persuasive reasoning as to why the directive is no longer necessary.



FERC has been instrumental in reducing the number of outstanding directives, as well. On November 21, 2013, in its order addressing the Paragraph 81 project, the Commission withdrew 41 directives, 24 of which were related to Reliability Standards, effective January 21, 2014.[23] The Commission identified Reliability Standards-related directives for withdrawal based on the following three guidelines:

(1) Whether the reliability concern underlying the outstanding directive has been addressed in some manner, rendering the directive stale;

(2) Whether the outstanding directive provides general guidance for Reliability Standards development rather than a specific directive; and

(3) Whether the outstanding directive is redundant with another directive.

[23] *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 145 FERC ¶ 61,147 (2013).

FERC staff participation on standard drafting teams has also been instrumental in addressing Reliability Standards directives. Increased participation by FERC staff allows their concerns to be raised early in the Reliability Standard development process and for issues to be vetted with industry. This open dialogue translates into fewer directives in FERC orders.

2. The Standards Independent Experts Review Panel

To set the foundation for a steady-state body of Reliability Standards, NERC established the IERP to evaluate the existing families of Reliability Standards and requirements. The Panel consisted of five independent industry experts and a sixth participant from FERC staff. Their areas of experience and competence included power systems engineering, relaying, transmission system planning, transmission and power system operations (including control center operations and dispatching, generation operations, transmission operations, and maintenance). The independent consultants brought executive leadership, experience from all three U.S. interconnections, experience with investor-owned utilities and public power as well as with vertically integrated and regional transmission organizations/independent system operator (RTO/ISO) market environments and small entities. The Panel also had experience working with Canadian provinces and Mexico. The Commission participant offered thorough knowledge of previous FERC orders and an understanding of the contributions of the requirements of various Reliability Standards to BPS reliability.

Due to the ongoing evolution of NERC's Reliability Standards, the Panel addressed requirements from two groups of Reliability Standards: (i) Reliability Standards that were, or would become, enforceable in 2013 (Enforceable in 2013 Standards); and (ii) Reliability Standards that will be enforceable in the future (Future Enforceable Standards). The Future Enforceable Standards and requirements included both Enforceable in 2013 Reliability Standards and those that, at the time of the Panel's report, had been approved by the NERC Board or by the

FERC and were currently pending enforceability.[24] Requirements pending replacement by approved Reliability Standards were not included in this group.

The Panel issued its report in June 2013 and presented the report to the NERC Board in August 2013. In the report, the Panel outlined a vision for how to transform the NERC Reliability Standards to steady-state. The Panel made seven short-term recommendations, three longer-term recommendations and seven additional recommendations.[25] The Panel's main recommendation was to retire 147 existing requirements of Reliability Standards, address seven areas (high-level gaps) not currently addressed by the Reliability Standards, and complete Reliability Standards development projects to address gaps within individual requirements. The Panel also made recommendations regarding compliance monitoring, prioritization for addressing the identified gaps, using risk to determine whether a future Reliability Standard is needed, and use of the Panel's identified criteria to determine quality and content as future Reliability Standards are developed. Finally, the Panel recommended a new construct to further consolidate Reliability Standards and required actions.

In evaluating whether a requirement should be retired, the Panel assessed whether each requirement: (i) did not support a reliability principle; (ii) met the Paragraph 81 criteria for retirement; or (iii) was better suited as a guideline rather than as a part of a Reliability Standard. For the requirements that the Panel did not recommend for retirement, the Panel applied content and quality criteria to examine whether they were steady-state or needed additional work. Specifically, the Panel examined the following content criteria: (i) whether the content of the

[24] The June 2013 report, *Standards Independent Experts Review Project – An Independent Review by Industry Experts*, is available at: http://www.nerc.com/pa/Stand/Standards%20Development%20Plan%20Library/Standards_Independent_Experts_Review_Project_Report.pdf.

[25] *Id*., p. 16-17.

requirement is technically correct, including identifying who does what and when; (ii) whether the requirement identifies the correct functional entities; and (iii) whether there are appropriate actions for which there should be accountability included or there is a gap. Additionally, the Panel examined the following quality criteria:

(1) Whether the requirement should stand alone or be consolidated with other Reliability Standards;

(2) Whether the requirement was drafted as a results-based standard;

(3) Whether a requirement is technologically neutral;

(4) Whether the requirement aligns with the purpose of the Reliability Standard;

(5) Whether the requirement is a higher solution than the lowest common denominator;

(6) Whether the requirement is measureable;

(7) Whether the requirement has a technical basis in engineering and operations;

(8) Whether the requirement is complete and self-contained;

(9) Whether the language is clear and does not contain ambiguous or outdated terms;

(10) Whether the requirement can be practically implemented; and

(11) Whether the requirement uses consistent terminology.

The Panel evaluated whether these remaining requirements addressed a risk to reliability by examining: (i) the ranking developed by the NERC RISC; (ii) the violation risk factor (VRF) for each requirement; and (iii) the Panel members' professional judgment.

These recommendations have been pivotal in NERC's evaluations of the Reliability Standards by standard drafting team subject matter experts (SME). Furthermore, the Panel's recommendations have been used to inform standard drafting teams and NERC's annual RSDPs, including the current, 2014-2016 RSDP. The potential reliability gaps identified by the IERP have been evaluated by the RISC and are assigned in some cases to active drafting projects. The

IERP recommendations that apply to Reliability Standards that are not part of active drafting projects are assigned to teams that conduct periodic reviews of Reliability Standards in the future for consideration.[26]

3. Implementation of the Paragraph 81 Project

The Paragraph 81 project was a separate project, carried out during the assessment period, in which requirements were recommended for retirement. This project stemmed from paragraph 81 of the Commission's March 15, 2012 FFT Order, in which the Commission invited NERC (and other interested entities) to propose specific Reliability Standards or requirements for revision or retirement if they did not provide meaningful benefit to BPS reliability. In response, NERC began the Paragraph 81 project to identify and retire Reliability Standards requirements that have little or no effect on reliability. As discussed above, the project established a set of criteria for evaluating whether a requirement should be considered for retirement.[27]

This initiative is reducing and simplifying the set of Reliability Standards with which registered entities must comply and which the ERO must monitor and enforce. This reduction in the body of requirements enables both the ERO and registered entities to redirect resources to matters posing greater risks to the reliability of the BPS and to ensure that the costs of reliability are proportionate to the benefits.

[26] These future periodic reviews are required by §13 of the SPM.

[27] For a detailed discussion of criteria used to determine if a Reliability Standard requirement should be retired, *see Paragraph 81 Project Technical White Paper* (December 20, 2012), available at: http://www.nerc.com/pa/Stand/Project%20201302%20Paragraph%2081%20RF/P81_Phase_I_technical_white_paper_FINAL.pdf.

In February 2013, NERC filed a petition with FERC to retire 34 requirements or sub-requirements within 19 Reliability Standards.[28] In its June 20, 2013 notice of proposed rulemaking (NOPR), the Commission indicated agreement that the requirements proposed for retirement either: (i) provided little protection for BPS reliability; or (ii) were redundant with other aspects of Reliability Standards. In addition, in the NOPR, the Commission proposed to withdraw several outstanding Commission directives relating to Reliability Standards.[29] On November 21, 2013, the Commission issued an order approving, as proposed in the NOPR, the retirement of 34 requirements and sub-requirements within 19 Reliability Standards, and withdrawing the identified directives effective January 21, 2014 (the Retirement Effective Date).[30] As noted above, the retirement of these requirements is enabling both the ERO and registered entities to redirect resources to matters posing greater risks to the reliability of the BPS and to ensure that the costs of reliability are proportionate to the benefits.

In the period leading up to the Retirement Effective Date, Regional Entities did not actively monitor compliance with the 34 retired requirements, nor did they process any new or existing possible violations of these retired requirements. Regional Entities also documented removal of any of the 34 retired requirements from Compliance Audit scopes in the final Compliance Audit reports for those audits. Within 30 days of the Retirement Effective Date, Regional Entities dismissed existing possible violations of the requirements being retired and issued dismissal letters to the registered entities.

[28] *Petition of the North American Electric Reliability Corporation for Approval of Retirement of Requirements in Reliability Standards*, Docket No. RM13-8-000 (Feb. 28, 2013).

[29] *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, Notice of Proposed Rulemaking, 143 FERC ¶ 61,251 (2013).

[30] *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 145 FERC ¶ 61,147 (2013).

In addition to the 34 requirements that the Commission approved for retirement, stakeholders submitted an additional 217 requirements for consideration for retirement. NERC is examining whether to retire these requirements through individual Reliability Standards development projects. Progress on this retirement effort is reported to the SOTC on a quarterly basis. As of the February 2014 SOTC meeting, 179 out of 281 recommendations had been addressed, 79 were under consideration in either a current project or in a periodic review, and 23 had not yet been assigned to a project.

4. Development of Compliance Assessment Tools Concurrently with Reliability Standards Development

Over time, one of the key improvement opportunities identified for NERC Reliability Standards has been to strengthen the connection between standard drafting teams and the compliance program, in order to clarify the expectations of Reliability Standard requirements. Two efforts at clarifying Reliability Standard requirements, but which ultimately illustrated the need for greater involvement of the Compliance department in the Reliability Standards development process, were the Compliance Application Notice (CAN) initiative and the Reliability Standard Audit Worksheets (RSAWs). CANs were notices drafted to respond to questions regarding how to assess compliance with specific Reliability Standards. CANs were posted on the NERC website to provide transparency to industry; however, since they were drafted well after the Reliability Standard was developed, the compliance assessment positions articulated in the CANs often varied from industry's perspective of the intent of the Reliability Standard or requirement. Similarly, prior to 2013, NERC developed RSAWs after regulatory approval of a Reliability Standard.

The CAN process demonstrated the need for concurrent development and dialogue between standard drafting teams and NERC Compliance Operations staff. As a result, in 2013,

NERC began incorporating the development of compliance assessment information into the Reliability Standards development process. After June 2013, informal development project teams began posting documents during standards development titled "compliance input." These documents provided questions from industry and answers developed by Compliance staff regarding how to assess compliance for specific requirements, or phrases in the requirements. This basic tool opened the door for conversation between the standard drafting teams and Compliance staff. It also allowed for conversation regarding the wording of requirements and the effect of that wording on how compliance would be assessed.

NERC then created an inter-departmental team to examine the development of RSAWs, which resulted in an internal policy on the development of RSAWs concurrent with Reliability Standards development projects. The policy included the following provisions:

(1) Coordinating input between standard drafting teams and NERC Compliance staff;

(2) Posting a draft RSAW during the formal comment period and prior to the ballot period for a Reliability Standard, allowing stakeholders to provide comments or to raise concerns at that time;[31] and

(3) Continuing to involve Regional Entity Compliance staffs in drafting RSAWs to strengthen compliance consensus throughout the ERO and capture additional subject matter expertise.

Today, RSAWs are written concurrently with new Reliability Standard development projects. They provide information regarding compliance assessment and testing. Reliability Standards staff leads coordination between the Standards and Compliance departments. Each Reliability Standards project is assigned dedicated staff support led by Compliance staff. Additionally, NERC Compliance staff are coordinating with Regional Entity Compliance staffs. This increased and ongoing coordination will help ensure that standard drafting teams, NERC

[31] The RSAWs themselves are not subject to the ballot.

and Regional Entity Compliance staffs and RSAWs are aligned as to the intent of Reliability Standards. By creating a uniform understanding of compliance expectations for each Reliability Standard early in the development process, the need for interpretations or other forms of subsequent compliance guidance should be reduced.

NERC Compliance staff will continue to supply standard drafting teams with compliance and enforcement information, statistics, and perspectives to help develop Reliability Standards that provide an increased reliability benefit and clarify compliance risks. Compliance staff will continue collaborating with industry and Reliability Standards staff early in the Reliability Standards development process in order to understand the intent of Reliability Standards under development and provide feedback on the proposed language of Reliability Standards. Finally, as described in greater detail in §II.C.2 and 4 below, NERC is working to provide training to auditors and industry on how to assess compliance with a new or revised Reliability Standard. This training is provided following FERC approval of a Reliability Standard, but well before its effective date.

5. Review of Regional Reliability Standards

A Regional Entity can propose adoption of a regional Reliability Standard to implement requirements that are more stringent than the continent-wide requirement, and/or to address a reliability concern that is unique to that Regional Entity and not addressed in a continent-wide Reliability Standard.[32] Today, a regional Reliability Standard requirement may be developed as a separate regional Reliability Standard or as an addendum to a continent-wide Reliability Standard. NERC is considering, based on the recommendations from the Panel, commissioning a team to evaluate regional Reliability Standards to identify candidates for retirement,

[32] **Attachment 3**, NERC Assessment of the Regional Entities' Delegated Functions, contains a discussion of each Regional Entity's regional Reliability Standards development activity during the assessment period.

consolidation with continent-wide Reliability Standards, or incorporation as variances within continent-wide Reliability Standards. The regional Reliability Standards that are not identified as candidates for retirement or consolidation should align with continent-wide Reliability Standards.

6. Improvements in the Reliability Standards Development Process

Transforming NERC Reliability Standards to a steady-state required changes to how NERC identified and resolved issues through the Reliability Standards development process. Implementing these changes was possible due to strong participation from industry stakeholders, the NERC SC and other NERC committees and workgroups, specifically the RISC, the SPIG, and the NERC technical committees, as well as FERC staff. The NERC Board and the NERC MRC also provided strong support to implement the changes.

a. Revisions to the *Standard Processes Manual* and Related Improvements

NERC's Reliability Standards development process is defined in the SPM, Appendix 3A to the NERC ROP. The SPM governs all NERC activities related to the development, approval, revision, reaffirmation, and withdrawal of Reliability Standards, interpretations, VRFs, violation severity levels (VSLs), definitions, variances, and reference documents developed to support Reliability Standards. It also addresses the respective roles of the NERC SC, standard drafting teams, and Registered Ballot Body members in the stakeholder process. Upon FERC's approval of revisions to the SPM in June 2013, NERC, the NERC SC, and stakeholders began implementing the approved changes into the Reliability Standards development process.

The revisions to the SPM were initiated in February 2012, when the NERC Board, in consultation with the NERC MRC, formed the SPIG.[33] The NERC Board tasked the SPIG with achieving the following objectives: (i) provide clarity on the reliability objectives, technical parameters, scope and relative priority of Reliability Standards; (ii) review the Reliability Standard drafting process to ensure that Reliability Standards contain specific technical content; and (iii) assess Reliability Standards project management.

After gathering input from stakeholders, the SPIG made five recommendations to modify the way NERC develops Reliability Standards.[34] Based on these recommendations, NERC worked with stakeholders to develop revisions to the SPM. In these revisions, NERC:

(1) Revised the composition of standard drafting teams to ensure that they are appropriately equipped to meet reliability objectives, namely by adding legal and compliance experts;

(2) Incorporated references to compliance assessment tool development, such as RSAWs, cooperatively and in parallel with Reliability Standard drafting;

(3) Streamlined commenting and balloting provisions as follows:

  (a) Allowing summary responses to comments;

  (b) Eliminating the obligation to respond in writing at every stage of the comment process; and

  (c) Eliminating negative votes without comments in the calculation of consensus.

(4) Incorporated the following provisions:

  (a) Quality review conducted in parallel with Reliability Standards development;

  (b) Guidance for the appropriate role and scope of interpretations, to be consistent with guidance from the NERC Board; and

[33] The SPIG is composed of the MRC chair and vice chair, other MRC members, two members of the NERC Board, the NERC chief executive officer (CEO), and the NERC SC chair.

[34] The SPIG's *Recommendations to Improve the NERC Standards Development Process* report is available on the NERC website at: http://www.nerc.com/pa/Stand/Standards%20Processes%20Manual%20revisions%20SPIG%20Recommen/Standards_Process_Input_Group_04.24.12_ver_8_FINAL.pdf.

(c) A waiver provision to allow for modifications to the Reliability Standards development process for good cause, with five days' notice and reporting of the exercise of a waiver to the NERC SOTC.

(5) Reduced the requirement for periodic reviews to be consistent with ANSI minimum requirements.

These improvements provide a balanced flexibility to the process, enabling NERC and industry to address pressing reliability issues on accelerated timeframes if necessary. Further, with the changes, the Reliability Standards development process continues to meet ANSI requirements. The Commission approved the proposed revisions on June 26, 2013, agreeing that these changes enable greater flexibility and efficiency.[35] Reliability Standards development projects initiated and completed after FERC's approval of the SPM changes have shown both significant increases in efficiency and improvements in the quality of the product.

In addition to the revisions to the SPM, NERC has implemented additional enhancements to the Reliability Standards development process. In conjunction with implementing changes to the SPM, in 2013, NERC spearheaded an "informal development" effort, which uses informal groups composed of industry subject matter experts to conduct early outreach to industry stakeholders prior to initiating formal development of new or revised Reliability Standards. This early outreach encourages stakeholder conversations to obtain inputs on the proposed Reliability Standards development project. This approach is positively affecting how standard drafting teams are conducting their work. The periodic reviews conducted in 2013 followed this same approach, acting as a tool for gathering stakeholder input. Recommendations from each periodic review team are then implemented through subsequently-formed standard drafting teams.

The most significant improvement from the changes to the Reliability Standards development process has been in the amount of time required to develop a quality Reliability

[35] *Order Approving Revisions to Electric Reliability Organization's Standard Processes Manual*, 143 FERC ¶ 61,273 (2013), at P 18.

Standard. As reported in the *Analysis of NERC Standards Process Results, Fourth Quarter 2013* filing,[36] the baselines for the amounts of time to revise an existing Reliability Standard and to develop a new Reliability Standard were approximately 27 months and 40 months, respectively. The amount of time to produce each of the Reliability Standard development projects that began formal development under the revised SPM was dramatically reduced.[37] Approximately six projects completed formal development, from posting the standard authorization request to being adopted by the NERC Board, in less than seven months.[38] Two other projects completed formal development in ten months.[39]

The changes to the standard development process have provided benefits in terms of standard drafting team management and staffing. The reduced time needed to develop a Reliability Standard combined with the fact that standard drafting team meetings are held closer together in time provide registered entities and other participants with increased flexibility in staffing standard drafting teams. As a result, standard drafting team members are able to stay more focused on the Reliability Standard development project.

The speed and efficiency of the process, particularly at the standard drafting team stage, have also benefited from the following process improvements:

- Smaller standard drafting teams with appropriate expertise have increased the ability to conduct activities and respond to stakeholders in a more-timely and effective manner;

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[36] Available at: http://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/Analysis_of_NERC_Standards_Process_Results_Q4_FINAL.pdf.

[37] The projects were: (i) 2010-01 – Training (PER); (ii) 2010-03 – Modeling Data (MOD B); (iii) 2010-04 – Demand Data (MOD C); (iv) 2012-05 – ATC Revisions (MOD A); and (v) 2013-04 – Voltage and Reactive Control (VAR).

[38] The six projects were: (i) GMD Phase 1; (ii) INT; (iii) Physical Security (CIP-014); (iv) MOD A; (v) MOD B; and (vi) PER projects; one of the two Reliability Standards in the VAR project (VAR-001) also met this benchmark.

[39] The two other projects were: (i) the remaining Reliability Standard in the VAR project (VAR-002); and (ii) the MOD C project.

- Open communication and concurrent development of compliance assessment tools have addressed compliance questions and allowed for clarification of compliance intentions during Reliability Standards development;

- Summary responses to comments has allowed standard drafting teams to consider stakeholder inputs, modify the draft Reliability Standard in response to those inputs, and repost it for industry review more quickly (as short as 1.5 weeks); summary responses are more concise while still addressing the issues, and provide visibility into the concerns in an easily digestible format;

- Not considering negative votes without comments in the calculation of consensus encourages entities to provide constructive comments, providing better insight into the issues for the standard drafting teams;

- Coordinating quality review in parallel with standard development has eliminated an additional step (that previously could require 4 to 6 weeks) from the process and improved focus on quality at an earlier stage; and

- Granting the NERC SC authority to waive provisions in the SPM for good cause gives the SC the ability to respond to urgent reliability issues. A recent example, discussed in §II.A.8.e below, is the development of Reliability Standard CIP-014-1 – Physical Security, in less than 90 days.

Another improvement resulting from the SPM revisions, which is also associated with increased outreach and communication, is the partnership created between NERC staff, standard drafting teams, and the NERC SC. Additionally, FERC staff has been providing early input regarding their perspectives during the standards development process, thereby giving standard drafting teams the opportunity to weigh those inputs early in the process. Based on experience to date, NERC anticipates that this open dialogue will result in FERC orders with either no directives or a significantly reduced number of directives.

The NERC SC, under the NERC Board's direction, also developed a strategic plan and work plan, as well as a revised charter, all of which were approved by the NERC Board on February 6, 2014.[40] These actions were designed to increase the NERC SC's effectiveness, efficiency, and ability to deliver high quality Reliability Standards. The *Standards Committee*

[40] The *Standards Committee Strategic Work Plan 2014-2016*, *Standards Committee Strategic Plan*, and amended *Standards Committee Charter* are available at: http://www.nerc.com/comm/SC/Pages/default.aspx.

Strategic Plan is a five-year plan that sets the vision and mission for the NERC SC, describes the guiding principles for the NERC SC, and sets the foundation for refocusing the activities of the NERC SC. The *Standards Committee Strategic Work Plan* is the tactical implementation of the *Standards Committee Strategic Plan*. The revised *Standards Committee Charter* clarifies the NERC SC's role in the development of steady-state Reliability Standards that provide for the reliability of the BPS, and ensures that the NERC SC develops a multi-year strategic vision that describes the goals and direction for the development of Reliability Standards consistent with the strategic and business plans of NERC.

Additionally, the NERC SC created a new subcommittee, the Process Management and Oversight Subcommittee (PMOS), that acts as an industry and standard drafting team partner. This subcommittee assigns a representative to each standard drafting team for the purpose of oversight. The oversight includes such actions as assisting the standard drafting team in understanding any stakeholder concerns, reaching out to stakeholders if they do not understand the actions being taken by the standard drafting team, being partners in reviewing the Reliability Standards for quality, and assisting with advice on a range of topics from direction to posting schedules. The PMOS has assisted standard drafting teams in avoiding or overcoming hurdles during the process.

The revisions made to the SPM and other changes made to the Reliability Standards development process, including strengthened partnerships among standard drafting teams, the NERC SC, and NERC staff, are showing great promise as improvements to the process, in terms of improving efficiency, speed and quality. These improvements have allowed the ERO to make significant progress towards achieving a body of steady-state Reliability Standards. The 2015-2107 RSDP will reflect that most, if not all, FERC directives and recommendations for

retirement (both from the Paragraph 81 project and the IERP review) will be addressed in 2015, and it will provide an opportunity for a strategic review of the Reliability Standards.

b. Formation and Work of the Reliability Issues Steering Committee

In response to the SPIG's recommendations, the NERC Board formed the NERC RISC in August 2012 to establish a collaborative effort at the industry leadership level to set priorities on issues of importance to the BPS. The RISC is composed of industry executives and thought leaders, including representatives from the NERC Operating, Planning, Standards, Critical Infrastructure Protection, and Compliance and Certification Committees. The RISC is an advisory committee that reports directly to the NERC Board, focusing on triaging and providing front-end, high-level leadership and accountability for issues of strategic importance to BPS reliability. The RISC assists the NERC Board, NERC technical committees, NERC staff, regulators, Regional Entities, and industry stakeholders in establishing a common understanding of the scope, priority, and goals for the development of solutions to address these issues. In doing so, the RISC provides a framework for steering, developing, formalizing, and organizing recommendations to help NERC and the industry effectively focus their resources on the critical means to improve the reliability of the BPS. In some cases, that includes recommending reliability solutions other than the development of new or revised Reliability Standards and offering high-level stakeholder leadership engagement and input on issues that enter the Reliability Standards process. In other cases, the development of a new Reliability Standard or modification of an existing Reliability Standard may be the best way to address a particular issue.

The NERC SC works closely with the RISC and the NERC technical committees, creating an alignment of focus on specific issues. The chairs of the technical committees and NERC SC are members of the RISC, which strengthens the needed coordination.

The RISC is developing a triage process to address other reliability issues that are brought to the NERC SC, whether through a standards authorization request or another mechanism. This process will include a review by the RISC to determine whether the issue is a risk to the reliability of the BPS and, if so, the priority of investing ERO and stakeholder resources to resolve the issue. This review will aid in focusing resources on the resolution of the most important issues.

The RISC also provides input into prioritizing Reliability Standards development activities by providing input to the RSDP in two ways: first, by considering whether the projects identified in the RSDP address areas of risk for the BPS; and second, by developing a priority rank for each of the projects.

In considering whether each of the projects addresses an area of risk for the BPS, the NERC RISC considers whether there are outstanding FERC directives or any recommendations for retirement, either from the Paragraph 81 project or the IERP, that could be addressed by the project.

In reviewing the priority of each project, the RISC provides a mechanism for addressing any scheduling conflicts between projects through the development process.[41] In its initial analysis, the RISC identified four high-priority focus areas for Reliability Standards: (i) cyber attacks; (ii) workforce capability and human error; (iii) protection systems; and (iv) monitoring and situational awareness. The RISC presented these priorities to the NERC Board in February 2013. In response, the NERC Board directed the RISC to conduct further analysis of the issues identified as high and medium priority. The NERC Board also directed that the RISC's input be integrated into the overall ERO planning process. NERC staff is implementing process steps to

[41] RISC reviewed and provided input on the use of RISC's rankings in project prioritization.

meet this objective. Subsequently, the RISC issued an updated report in August 2013 identifying a fifth area of focus: adaptation and planning for change.[42]

In addition to the activities described above, in November 2012, the RISC participated in a NERC-sponsored conference in which reliability topics were discussed with technical experts. The conference, conducted as a series of panel discussions, highlighted several existing and emerging reliability risks and created an opportunity for informed dialogue about technical topics. A second conference, the Reliability Leadership Summit, was held in October 2013, with key industry decision-makers gathering to discuss reliability priorities and industry trends.[43]

Efforts to review the risk areas identified by the RISC and to develop appropriate risk management strategies are ongoing. Integrating these priorities into the annual business plan and budget process will be a cornerstone of NERC's annual planning process going forward. To effect this change in planning, NERC has developed the Reliability Risk Management (RRM) process, a multi-year strategy development method that uses industry expertise through the RISC and other standing committees to develop actionable, measureable efforts to manage reliability risk. The RRM process is discussed in detail below in §II.D.1.

c. Realignment of Resources in the Reliability Standards Program

NERC is constantly assessing the alignment of resources to be responsive to the changes necessary to move the NERC Reliability Standards to a steady-state. In 2013, NERC realigned resources in its Reliability Standards department by creating multiple small teams of Reliability Standards developers and one team focused on information management. This realignment focused resources on the production of Reliability Standards rather than on executing and

[42] *ERO Priorities – RISC Updates and Recommendations* is available at: http://www.nerc.com/comm/RISC/Related%20Files%20DL/RISC_Priority_Recommendations-Jul_26_2013.pdf.

[43] NERC intends for this summit meeting to be an annual event; the next Reliability Leadership Summit is scheduled for September 2014.

monitoring the development process, thereby increasing the throughput to complete outstanding projects and resolve outstanding directives. In 2013, each of the three "developer" teams was assigned one of the following high-level goals:

(1) Resolving directives;

(2) Conducting the required five-year reviews for current Reliability Standards;[44] or

(3) Overseeing emerging issue projects and the completion of remaining open projects.

The small developer teams closely coordinate with one another to ensure a balance in workload and to create an expertise in each of the major work areas.

Additionally, NERC has improved the composition of standard drafting teams by enhancing the selection process to identify, for each project, the necessary technical, writing, and project management expertise to form a balanced team that will foster improved effectiveness and enhanced efficiency. Standard drafting teams also now receive increased NERC staff support, including dedicated legal support, for each project. Each standard development project is staffed by a lead standard developer, and many projects have a second supporting standard developer. Standard developers provide project management and facilitation experience as well as additional skills, including technical writing, legal skills, and outreach/consensus-building skills, to the standard drafting team, which contributes to the development of high-quality Reliability Standards. With this enhanced staffing, standard drafting teams are better able to reach milestones and build consensus among industry stakeholders in advance of balloting. Further, NERC now provides facilitation training to all newly appointed standard drafting team leaders. Finally, NERC has developed a Standards Development Process Participant Conduct

[44] Section 13.0 of the revised SPM now requires periodic reviews every five years for those Reliability Standards that have been adopted by ANSI as an American national standard, and every ten years for all other Reliability Standards.

Policy to ensure that the Reliability Standards development process is conducted in a professional and constructive environment.

d. Developing and Implementing Procedures for the Cost-Effective Analysis Process

NERC has developed the Cost-Effective Analysis Process (CEAP) in response to requests by registered entities and regulators to incorporate consideration of costs more directly into Reliability Standard development activity.[45] The CEAP affords stakeholders an opportunity to share projected cost information regarding implementation of draft Reliability Standards and provides the opportunity to offer alternatives that would be equally, or more, efficient at achieving the reliability objective of the draft Reliability Standard while also taking into consideration implementation costs. CEAP has been used for a limited number of new and revised Reliability Standards projects, with limited success. NERC continues to explore options for improving both the process and the quality of the resulting information.

The current CEAP process provides for a two-phase process for identifying projected implementation costs. The first phase of the CEAP, identified as the Cost Impact Analysis, is conducted during the standard authorization request stage of Reliability Standard development. It provides an opportunity to identify approximate implementation costs associated with a proposed Reliability Standard prior to its development. Information related to the mission and forecasted implementation costs of the proposed Reliability Standard is collected from the industry during the initial standard authorization request comment period. The information collected is shared with the NERC SC and the standard drafting team, and is posted on the NERC website.

[45] This was an issue raised in response to the five-year performance assessment survey.

The second phase of the CEAP, identified as the cost effective analysis, typically comes after the draft Reliability Standard is developed by the standard drafting team and is ready for the first combined formal comment period and ballot. During this phase, NERC again solicits industry to provide forecasted implementation costs of the proposed requirements and to propose alternative methods to achieve the proposed Reliability Standard's reliability objective more efficiently. Any alternative proposals provided by industry during this phase should contain sufficient technical justification, and if possible, cost comparison data for consideration.

7. Improved Stakeholder Access to Reliability Standards Information

All Reliability Standards are available to stakeholders through NERC's public website, including: (i) Reliability Standards that are currently enforceable in specific jurisdictions (i.e., in the U.S. and Canadian provinces); (ii) Reliability Standards pending regulatory approval; (iii) Reliability Standards approved by the NERC Board and pending regulatory filing; and (iv) Reliability Standards no longer subject to enforcement. In 2012, NERC launched an improved interface to allow stakeholders to filter the complete set of Reliability Standards so that they could identify which Reliability Standards are applicable to their respective registered functions. Work is ongoing to improve the completeness and timeliness of this information for non-U.S. jurisdictions (i.e., Canadian provinces or Mexico).

Additionally, beginning in 2013, interested entities can track current Reliability Standards development projects in a publicly posted spreadsheet, the *Project Tracking Spreadsheet*.[46] NERC updates this spreadsheet monthly. The spreadsheet also provides a link to the projects page, the deliverables, the number of Paragraph 81 requirements, the number of regulatory directives or guidance, the PMOS liaison assigned to the project, the NERC standards developer,

[46] NERC regularly updates the *Project Tracking Spreadsheet: 2014 Project Work Plan* and the link to the file is located on the left side of NERC's Standards webpage available at: http://www.nerc.com/pa/Stand/Pages/Default.aspx.

and a month-by-month timeline. Also in 2013, NERC began posting the *Projected Standards Posting Schedule*, which provides the industry with an outlook of near term postings.

8. Specific Reliability Standards Projects

a. Critical Infrastructure Protection Version 5 Reliability Standards

On November 22, 2013, the Commission issued Order No. 791 approving the Critical Infrastructure Protection Version 5 (CIP Version 5) Reliability Standards.[47] The CIP Version 5 Reliability Standards provide a cybersecurity framework for the categorization and protection of BES cyber systems to support the reliable operation of the grid. NERC worked with industry to ensure that the CIP Version 5 Reliability Standards address the differing roles of each registered entity in the operation of the BES, the criticality and vulnerability of the BES cyber systems needed to support BES reliability, and the risks to which the BES cyber systems are exposed. In Order No. 791, the Commission found that CIP Version 5 is an improvement over the currently approved CIP Reliability Standards. The Commission also determined that categorizing BES cyber systems based on their impact on the reliable operation of the BES (Low, Medium, or High), with all BES cyber systems categorized as at least Low Impact, offers more comprehensive protection of the BES.[48] The Commission directed NERC to address several new directives, some of which must be addressed within a year. To meet these directives, NERC has established a standard drafting team and set an aggressive schedule to address all the Commission's concerns, consistent with the timeline set by the Commission.

In Order No. 791, the Commission also approved NERC's proposal to bypass CIP Version 4 and move directly to implement CIP Version 5. Recognizing that registered entities

[47] *Version 5 Critical Infrastructure Protection Reliability Standards*, Order No. 791, 145 FERC ¶ 61,160 (2013).

[48] In Order No. 791, the Commission directed NERC to develop modifications to address specified concerns with the CIP Version 5 standards, including: (i) the "identify, assess, and correct" language; (ii) protections for Low Impact BES Cyber Systems; (iii) the risks posed by transient devices; and (iv) the protection of communication networks.

are in various stages of implementation of CIP Versions 3 and 4, NERC tackled the need for flexibility as well as the need to identify and address the associated transition challenges for industry. In October 2013, NERC launched the CIP Version 5 Transition Implementation Study (CIP Version 5 Study) to collect and to evaluate relevant data from select responsible entities regarding their experience in implementing CIP Version 5 requirements. Through this study, NERC is identifying successful implementation methods and challenges that the industry faces in transitioning to CIP Version 5. On October 11, 2013, NERC submitted an informational filing to the Commission that described how the CIP Version 5 Study would assist responsible entities in making the transition to CIP Version 5.[49] As part of the CIP Version 5 Study, NERC selected a group of six responsible entities, based on factors including willingness to participate, past performance under the CIP Reliability Standards, and expected relevance to the CIP Version 5 Study's goals. NERC is sharing the experience and information obtained through the CIP Version 5 Study with industry throughout the study period. NERC will also prepare a final report that synthesizes the study participants' experiences in applying CIP Version 5. The report will focus on the effectiveness of meeting the CIP Version 5 requirements and the methods employed during implementation. The report will also focus on the following:

(1) Methods, approaches, and policies that were effective in implementing the technical controls of CIP Version 5;

(2) Tools, policies, and training that were effective in aligning employees' skills and cooperation with the responsible entity's mission and the CIP Version 5 Reliability Standards;

(3) Hurdles encountered by the participating responsible entities and the relevant outcomes; and

(4) Requirements and concepts of CIP Version 5 that the responsible entities had difficulty implementing and why.

[49] *Informational Filing of the North American Electric Reliability Corporation Regarding the CIP Version 5 Reliability Standards Implementation Study*, Docket No. RM13-5-000 (Oct. 11, 2013).

b. Transmission Vegetation Management

During the assessment period, the Commission approved two new versions of the FAC-003 Reliability Standard. In Order No. 777,[50] the Commission approved NERC's proposed FAC-003-2, a Reliability Standard that requires responsible entities to minimize encroachments from vegetation located adjacent to transmission rights-of-way and within a transmission owner's control. Historically, vegetation-related outages have been a recurring contributor to blackouts. In fact, inadequate vegetation management practices causing tree contact was one of the initiating causes of the 2003 Northeast blackout. Industry compliance with FAC-003-2, together with a continued industry focus on best practices for vegetation management, enhances the reliability of the BPS.

FAC-003-2 is the first results-based Reliability Standard approved by the Commission, and contains several improvements over FAC-003-1. For example, while FAC-003-2 continues to apply to overhead transmission lines operated at or above 200 kV, it additionally applies to any lower voltage overhead transmission line that is either an element of an interconnection reliability operating limit or a major WECC transfer path. Another improvement is that FAC-003-2 makes explicit a transmission owner's obligation to prevent an encroachment into the minimum vegetation clearance distance for a line subject to this standard, regardless of whether that encroachment results in a sustained outage or fault. FAC-003-2 also requires transmission owners, for the first time, to annually inspect all transmission lines subject to the Reliability Standard and complete 100 percent of their annual vegetation management work plan.

[50] *Revisions to Reliability Standard for Transmission Vegetation Management*, Order No. 777, 142 FERC ¶ 61,208 (2013) (Order No. 777).

On September 19, 2013, the Commission approved FAC-003-3,[51] which extends FAC-003-2 vegetation management requirements to certain generator interconnection facilities to address a reliability gap that existed when the requirements only applied to transmission owners. Certain generator owners with overhead lines, particularly those with generator interconnection facilities longer than one mile and which run through areas that may be densely populated with trees and other plants, are now also required to perform vegetation management of those lines. For purposes of this Reliability Standard, these lines are treated as transmission lines.

NERC is conducting additional research relating to vegetation management issues in response to Commission directives in Order No. 777. The Commission directed NERC to conduct or contract testing to develop empirical data regarding the flashover distances between conductors and vegetation.[52] To carry out this project, NERC is contracting support to conduct the necessary research and testing that will provide empirical evidence to statistically validate the calculation of the minimum vegetation clearance distances (MVCD), as specified in Reliability Standard FAC-003-3. Significant industry support for the application of the Gallet Equation, which uses the gap factor to calculate MVCD, was a key factor in achieving approval for this NERC Reliability Standard. A final report summarizing this research will be filed with the Commission in June 2015 and will advise the Commission about the issues encountered and how best to address them.

c. Protection System Maintenance and Testing

NERC has identified protection systems, and in particular reduction of protection system misoperations, as a top reliability priority. Likewise, the RISC has named protection systems as one of four high priority areas to be addressed in Reliability Standards. In particular, properly

[51] *Generator Requirements at the Transmission Interface*, 144 FERC ¶ 61,221 (2013).

[52] Order No. 777 at P 59.

maintaining protection systems supports the ERO's goal of reducing protection systems misoperations. By reducing misoperations, maintenance and testing of protection systems helps provide reliable system performance when responding to abnormal system conditions.

In 2007, NERC initiated Project 2007-17 – Protection System Maintenance and Testing – to consolidate four currently enforceable Reliability Standards[53] that pertain to various aspects of maintenance and testing of protection and control systems into a single Reliability Standard, PRC-005-2. This project also seeks to address: (i) certain Commission directives from Order No. 693 related to these four Reliability Standards;[54] and (ii) fundamental issues identified by the NERC System Protection and Control Task Force (SPCTF) in its assessment of these four Reliability Standards.

On December 19, 2013, the Commission approved Reliability Standard PRC-005-2,[55] Protection System Maintenance, which establishes requirements for a time-based maintenance program, where all relevant devices are maintained according to prescribed maximum

[53] The four Reliability Standards at issue were PRC-005-1, PRC-008-0, PRC-011-0, and PRC-017-0. *See NERC SPCTF Assessment of Standards: PRC-005-1 — Transmission and Generation Protection System Maintenance and Testing, PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs, PRC-011-0 — UVLS System Maintenance and Testing, PRC-017-0 — Special Protection System Maintenance and Testing*, Mar. 8, 2007 (SPCTF Assessment), available at: http://www.nerc.com/docs/standards/sar/PRC-005-008-011-017_Report_Approved_by_PC.pdf.

A supplement to the SPCTF Assessment was also considered. *See NERC SPCTF Supplemental Assessment Addressing FERC Order 693 Relative to PRC-005-1 — Transmission and Generation Protection System Maintenance and Testing, PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs, PRC-011-0 — UVLS System Maintenance and Testing, PRC-017-0 — Special Protection System Maintenance and Testing*, May 17, 2007, available at: http://www.nerc.com/docs/pc/spctf/Supplemental_Report_on_PRC-005-008-011-017_Approved_by_PC_2.pdf.

[54] The Commission approved Reliability Standard PRC-005-1 in Order No. 693 and directed NERC "to develop a modification … through the Reliability Standards development process that includes a requirement that maintenance and testing of a protection system must be carried out within a maximum allowable interval that is appropriate to the type of the protection system and its impact on the reliability of the Bulk-Power System." The Commission also directed NERC to consider suggestions made by commenters to "combine PRC-005, PRC-008, PRC-011, and PRC-017 into a single Reliability Standard." Order No. 693 at P 1475.

[55] On March 30, 2011, NERC submitted a petition for Commission approval of a proposed modification to the definition of "Protection System" to close a reliability gap created by an omission in the prior definition. The Commission approved the modified definition, which is used in PRC-005-2. *See North American Electric Reliability Corporation*, 138 FERC ¶ 61,095 (2012).

intervals.[56] It also establishes requirements for a condition-based maintenance program, where the hands-on maintenance intervals are adjusted to reflect the known and reported condition of the relevant devices. For a performance-based maintenance program, the hands-on maintenance intervals are adjusted to reflect the historical performance of the relevant devices. PRC-005-2 also provides a comprehensive set of requirements that define a strong protection systems maintenance program. It also includes detailed tables of minimum maintenance activities and maximum maintenance intervals for all five component types addressed within the NERC definition of protection system. Functional entities that monitor the actual condition of their protection system components are further empowered to utilize monitoring to improve the efficiency and effectiveness of their protection systems maintenance program. With the benefit of extensive protection system performance data, these entities will improve the efficiency and effectiveness of their programs.

This Reliability Standard will go into effect on April 1, 2015, and implementation will continue over a twelve-year phased-in period, which includes milestones for implementation during the implementation timeframes. In furtherance of the important issues surrounding the maintenance and testing of protection systems, the System Protection and Control Subcommittee (SPCS) issued a report that suggested improving commissioning practices through: (i) analysis of protection system misoperations; (ii) sharing of lessons learned; and (iii) development of an industry reference document on protection system commissioning practices.[57]

[56] *Protection System Maintenance Reliability Standard*, 145 FERC ¶ 61,253 (2013)

[57] *See* the Planning Committee-approved final report, *SPCS Response to Standards Committee Request for Research*, (Mar. 5, 2013), available at: http://www.nerc.com/docs/pc/spctf/SPCS%20Commissioning%20Testing%20Response_Final.pdf.

d. Geomagnetic Disturbances

As high-impact, low-frequency (HILF) events, severe GMDs pose a unique threat to BPS reliability. NERC is committed to working with stakeholders and the Commission to mitigate the risks posed by such events. The science concerning GMDs is still maturing and there is significant disagreement in the scientific and manufacturing communities about the most likely effects of a GMD event on the BPS, but NERC recognizes the potential for GMDs to adversely affect the BPS. Occurrences such as the 1989 event in Hydro-Québec demonstrate that severe solar storms have potential to cause loss of reactive power support, voltage instability, relay misoperations, and possibly equipment loss of life or damage to the BPS.

Through the efforts of the Geomagnetic Disturbance Task Force (GMDTF), NERC released the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System* in February 2012.[58] The GMDTF identified four recommendations for industry in the report:

(1) Improve tools for industry planners to develop geomagnetic mitigation strategies;

(2) Improve tools for system operators to manage geomagnetic impacts;

(3) Develop education and information exchanges between researchers and industry; and

(4) Review the need for enhanced NERC Reliability Standards.

With implementation of these recommendations well underway, the Commission issued Order No. 779 concerning Reliability Standards for GMDs on May 16, 2013.[59] In Order No. 779, the Commission directed NERC to submit for approval proposed Reliability Standards that address the impact of GMD on the reliable operation of the BPS, in two stages. In the first stage,

[58] Available at: http://www.nerc.com/pa/stand/pages/geomagnetic-disturbance-resource.aspx.

[59] *Reliability Standards for Geomagnetic Disturbances*, Order No. 779, 143 FERC ¶ 61,147 (2013).

NERC was directed to develop one or more Reliability Standards that require owners and operators of the BPS to implement operational procedures to mitigate the effects of GMDs consistent with the reliable operation of the BPS. On November 14, 2013, well within the six-month time frame directed by the Commission, NERC submitted a petition requesting Commission approval of the first GMD Reliability Standard.[60] The proposed standard, EOP-010-1, requires entities to develop tailored operating plans, processes, and procedures.

In the second stage, NERC was directed to submit one or more Reliability Standards that require owners and operators of the BPS to conduct initial and on-going assessments of the potential impact of benchmark GMD events on BPS equipment and the BPS as a whole. NERC and the standard drafting team assigned to develop GMD Reliability Standards have completed development of a technically justified benchmark GMD event during the first half of 2014 in preparation for completion of Reliability Standard development in late 2014.

The following efforts resulting from implementation activities have been important in supporting development of technically sound Reliability Standards, as ordered by the Commission:

(1) Development of operating procedure templates for transmission operators that reflect best practices and consensus among technical experts;

(2) Improved ground conductivity models that represent the geological regions of North America and a published guidance for modeling geomagnetically-induced current; and

(3) Initiation of a transformer modeling and testing project to validate models used to assess the effects of geomagnetically-induced current on transformers.

NERC is continuing efforts to expand the technical foundation for understanding the potential impact of GMD by supporting the work of the GMDTF and collaborative research with

[60] *Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard EOP-010-1 – Geomagnetic Disturbance Operations*, Docket No. RM14-1-000 (Nov. 14, 2013).

the Electric Power Research Institute, U.S. Geological Survey, Natural Resources Canada, and other public and private research organizations. The GMDTF and the Electric Power Research Institute are giving focused attention toward improving the suite of publicly available and technically valid tools, guidelines, and transformer models to evaluate potential impacts of GMD. The results of this work will support registered entities in conducting vulnerability assessments as required by the second stage Reliability Standards being developed in response to Order No. 779.

e. Physical Security Reliability Standard

On March 7, 2014, FERC issued an order directing NERC to submit for approval, within 90 days of the order, one or more Reliability Standards to address physical security risks and vulnerabilities of critical facilities on the BPS. FERC's order focused on critical facilities, directing steps to evaluate physical security threats and implement security plans that continues NERC's ongoing physical security efforts. In the order, FERC stated, among other things, that the proposed Reliability Standard(s) should require entities to take at least the following three steps:

(1) Perform a risk assessment to identify facilities that, if damaged or rendered inoperable, could result in instability, uncontrolled separation, or cascading failures on the BPS;

(2) Evaluate the potential threats and vulnerabilities to those identified facilities; and

(3) Develop and implement a security plan designed to protect against physical attacks to those identified facilities based on the assessment of the potential threats and vulnerabilities to their physical security.

The Commission's order also specified that the Reliability Standard should require procedures for a third party to verify the list of identified facilities and add or remove facilities from the list, procedures for a third party to review the evaluation of threats and vulnerabilities and the

physical security plan, and that the three steps listed above be periodically re-evaluated and revised.

In response to the order, NERC staff and the NERC SC worked together to develop an action plan for meeting the June 5, 2014 deadline. The NERC SC approved several waivers to facilitate meeting the required timelines and formed the eleven member standard drafting team on March 21, 2014. Also on March 21, 2014, the NERC SC approved waivers to support drafting activities to meet the June 5, 2014 deadline. Additionally, on March 21, 2014, the NERC SC also accepted the Project 2014-04 standard authorization request for a seven calendar-day informal comment period posting, pursuant to the NERC SC-approved waiver. On April 1, 2014, NERC staff convened a technical conference to focus stakeholder discussion on developing a draft of a Physical Security Reliability Standard, with the intent of assisting the standard drafting team to quickly develop and post a Reliability Standard for comment and ballot. The conference provided a forum for industry input on the concepts in the draft Reliability Standard, to include criteria for determining applicable entities, identification of critical facilities, evaluation of potential threats and vulnerabilities, development and implementation of physical security plans, and the proposed standard's implementation plan. NERC Compliance staff also provided an overview of the RSAW approach.

The Physical Security standard drafting team developed the proposed Reliability Standard, CIP-014-1 through the Reliability Standards development process. The Reliability Standard was posted under a NERC SC-approved waiver for a 15-day concurrent comment and initial ballot period from April 10, 2014 through April 24, 2014. The initial ballot achieved a quorum of 88.60 percent and an industry approval of 82.07 percent. The final ballot was posted, under an SC-approved waiver, for a 5-day period from May 1, 2014 through May 5, 2014 and

achieved a quorum of 92.53 percent and an industry approval of 85.61 percent. The NERC Board adopted the standard on May 13, 2014, and it was filed with FERC by NERC on May 23, 2014.

B. The ERO Is Implementing Processes to Register Entities Commensurate with Risk to the Bulk Power System

The starting point for the ERO's program for monitoring and enforcing compliance with Commission-approved Reliability Standards is its processes for comprehensively identifying and registering owners, operators and users of the BPS that are responsible for performing reliability-related functions in accordance with the approved Reliability Standards. This section discusses major enhancements to the registration process initiated during the assessment period.

1. Improved Registration Processes, Information Systems, and Methods Across Regional Entities

NERC's organization registration process identifies entities that are responsible for compliance with the Commission-approved Reliability Standards. Entities that are registered are included on the NERC Compliance Registry (NCR) and are responsible for compliance with all applicable Reliability Standards. Pursuant to Section 500 of the NERC ROP and the terms of the approved Regional Entity delegation agreements (RDAs), the Regional Entities are responsible to provide timely and accurate information to NERC relating to registrations to enable NERC to maintain a NCR that is accurate and up-to-date.[61] To further consistency and increase transparency in registrations across the Regional Entities, as well as to address the problem of obtaining timely updates of registration information from entities, NERC developed a Common Registration Form (CRF) which registered entities use to provide the Regional Entities with real-

[61] The amended and restated RDAs, effective January 1, 2011, included revisions to the provisions concerning the Regional Entities' responsibilities in the registration process. In addition, revisions to the registration criteria and registration processes were effectuated through amendments to NERC ROP Section 500, Appendix 5A, *Organization Registration and Certification Manual*, and Appendix 5B, *Statement of Compliance Registry Criteria*, during the assessment period.

time updates of the information recorded in the NCR pertaining to ownership, operations, contact information, asset lists and other information that may affect registration status. A corollary benefit of the CRF is that it serves as a check for the Regional Entities to ensure that owners, users, and operators of the BPS are appropriately registered. NERC is also undertaking an effort to map all the inter-relationships between registered entities on the NCR, to ensure that all owners, users and operators of the BPS are registered in the NCR.

In January 2014, NERC launched the Risk-based Registration Assessment Initiative to enhance the compliance registration and certification program to be more efficient and better aligned with reliability benefit. Through this initiative, NERC will register entities and assign appropriate Reliability Standard requirements commensurate with the need to mitigate the risk that each entity poses to the BES, by scaling registration criteria based on their contributions to reliability. NERC will also develop tools that will enhance registered entities' understanding of the relevant Reliability Standards and requirements that apply to them. Scoping compliance responsibilities according to BPS reliability risks equates to better use of resources at both the registered entity level in the implementation of compliance programs, and at the Regional Entity level in their overall compliance monitoring efforts.

2. BES Definition

During the assessment period, NERC revised the definition of the BES in the NERC *Glossary of Terms Used in Reliability Standards*, in response to Commission directives in Order Nos. 743 and 743-A.[62] The objective of the revisions is to ensure consistent inclusion or exclusion of entities and elements that are subject to Reliability Standard requirements. With the strong support and participation of industry representatives and the Regional Entities, NERC

[62] *Revision to Electric Reliability Organization Definition of Bulk Electric System*, Order No. 743, 133 FERC ¶ 61,150 (2010), *order on reh'g*, Order No. 743-A, 134 FERC ¶ 61,210 (2011).

delivered a technically grounded and legally supportable foundation for identifying the elements and facilities that comprise the BES.

In Phase 1 of this process, NERC proposed to eliminate regional discretion and establish a bright-line threshold that includes in the BES all facilities operated at or above 100 kV. The Commission accepted the revised definition in Order No. 773.[63] NERC also identified specific categories of facilities and configurations as inclusions and exclusions to the BES definition. These inclusions and exclusions are set forth in the revised BES definition. The process for requesting an inclusion or exclusion in or from the BES, is set forth in Appendix 5C, *Procedure for Requesting and Receiving an Exception from the Definition of the Bulk Electric System*, of NERC's ROP, which FERC has also approved.[64] Appendix 5C establishes an exception process to bring elements within, or remove elements from, the BES definition on a case-by-case basis.

In Phase 2 of the BES definition process, NERC addressed additional regulatory directives from Order Nos. 773 and 773-A, as well as industry comments received during Phase 1. As part of Phase 2, and with industry input, NERC proposed substantive changes to Inclusion I4 (dispersed power producing resources), Exclusion E1 (radial systems), Exclusion E3 (local networks), and Exclusion E4 (reactive power devices). The Commission approved the additional proposed revisions to the BES definition in an order issued March 20, 2014.[65]

The Commission-approved revised BES definition enables NERC and the Regional Entities to identify assets that are material to the reliability of the interconnected transmission

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[63] *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, Order No. 773, 141 FERC ¶ 61,236 (2012); *order on reh'g*, Order No. 773-A, 143 FERC ¶ 61,053 (2013), *order on reh'g and clarification*, 144 FERC ¶ 61,174 (2013).

[64] Available at: http://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/Appendix_5C_ProcForReqAndRecExFromAppOfNERCDefBES_20140701.pdf.

[65] *North American Electric Reliability Corporation, Order Approving Revised Definition*, 146 FERC ¶ 61,199 (2014).

network. By using a set of continent-wide, "bright line" criteria that eliminates regional discretion, the revised definition effectively ensures that the users, owners and operators of BES assets are identified and registered on a consistent basis in order to comply with applicable Reliability Standards. The revised BES definition provides improved clarity for industry by identifying specific categories of facilities and configurations as inclusions and exclusions to the BES. Additionally, the case-by-case exception process to add elements to, and to remove elements from, the BES provides transparency and uniformity to the determinations of what constitutes the BES.

To implement the revised BES definition, which became effective on July 1, 2014, NERC developed a web-based, ERO Enterprise-wide application, the BESnet Enterprise Application Tool (BESnet tool), to provide a consistent platform for registered entities to submit self-determined notifications and to submit exception requests for inclusions in or exclusions from the BES. Once a registered entity applies the BES definition to a specific element within its system, it must notify its applicable Regional Entity of any newly identified system elements that are inclusions or exclusions (i.e., system elements with changed BES classifications under the revised BES definition). Inclusion and exception decisions on the self-determined notifications are made by the Regional Entity through the BESnet tool in order to support uniform reviews and evaluations by the Regional Entity and NERC. If a Regional Entity receives notification of a self-determined exclusion, then it must evaluate whether that registered entity can stop its compliance obligations for that excluded system element. If a Regional Entity receives notification of a self-determined inclusion, then the Regional Entity must evaluate whether that registered entity should take steps to bring that system element into compliance with applicable Reliability Standard requirements within a fixed implementation period. NERC

will also use the BESnet tool to manage associated support materials and records related to technical reviews by the Regional Entities and NERC.

NERC is finalizing implementation materials that will guide the consistent evaluation of inclusions, exclusions and self-notifications of BES elements across the ERO Enterprise. NERC has created a single portal location to provide a central site to obtain useful materials to support registered entities' review of their BES elements. Additionally, the BES exception process was identified by NERC and the Regional Entity Management Group as having sufficient similarities in business processes and function across the ERO to be deemed an ERO Enterprise application, which will be used by both NERC and the Regional Entities to eliminate disparate applications across the ERO. NERC is also developing a Reliability Standard reference document to explain the intended application of the BES definition to yield consistent results. Development of additional reference documents to promote further consistency across the ERO Enterprise includes:[66]

(1) *BES Definition Reference Document*, which addresses how to apply the BES definition using several examples;

(2) *BES Definition Implementation Guidance*, which shows how the Regional Entities and NERC will review self-determined notifications and includes a high-level summary of notification requirements; and

(3) *BES Exception Request Evaluation Guideline*, which demonstrates how the Regional Entities and NERC will evaluate exception requests, and provides a high-level summary of the exception request evidentiary requirements.

During the first two quarters of 2014, NERC held communications and training sessions for Regional Entities, registered entities, and NERC staff to address, among other things: (i) evidentiary requirements for BES determinations; (ii) review and appeal mechanisms; and (iii) Reliability Standards applicability. These sessions included workshops and webinars.

[66] *See* the Bulk Electric System (BES) Definition, Notification, and Exception Process Page at: http://www.nerc.com/pa/rapa/pages/bes.aspx.

C. The ERO Monitors and Enforces Compliance with Reliability Standards in an Efficient and Transparent Manner Using Enforcement Processes that Match the Risk and Importance of Possible Violations to BPS Reliability

A key, strategic transformation that NERC, in collaboration with the Regional Entities and stakeholders, embarked upon during the assessment period is the construction of a risk-based model for compliance monitoring and enforcement. This risk-based approach enables NERC to focus ERO and industry resource investment on the most important issues to BPS reliability. In this section of the assessment report, NERC highlights initiatives to improve the Compliance Monitoring and Enforcement Program (CMEP) during the assessment period, including the FFT program. The FFT program and its subsequent enhancements began to implement this risk-based approach. The FFT program enables the ERO Enterprise to achieve major efficiencies in enforcement. Through the use of FFT, the ERO resolves noncompliances that pose a lesser risk to BPS reliability more efficiently, recognizing that efficient disposition of such issues allows the ERO Enterprise and industry to devote its emphasis and resources to more important reliability matters. Further, through careful planning and coordination and collaboration between NERC and the Regional Entities, NERC has achieved major enforcement efficiencies. These efforts have also resulted in a drastically reduced NERC caseload; for the past two years, NERC and the Regional Entities have worked to eliminate all items in the caseload which are older than 24 months. In 2012, that effort resulted in a reduction of those items by 80%. In 2013, the ERO Enterprise reduced those items by 93%. By the end of 2013, only 65 violations in inventory were older than 24 months. Additionally, taking advantage of the FFT process, which provides incentives for self-reporting, registered entities continue to aggressively self-identify, self-report and mitigate reliability issues.

Building upon the success of FFT through the RAI, NERC and the Regional Entities created additional incentives to discourage poor performance and encourage positive behaviors

that contribute to higher accountability and improved reliability performance. RAI processes that promote more effective reliability risk mitigation by encouraging development and enhancement of internal management controls and corrective action programs at registered entities began to be implemented in 2013.[67]

1. Compliance Enforcement Initiative and Find, Fix, Track and Report

Recognizing the need and the importance of ensuring that reliability risks are addressed properly through a scaled approach, NERC devised the FFT initiative in 2011 as a risk control strategy that differentiates and addresses compliance issues according to their significance to the reliability of the BPS. FFT emphasizes proportionality and enforcement discretion. The FFT process enables NERC to report lesser-risk possible violations of Reliability Standards through a streamlined process that results in the posting of a minimal record associated with the noncompliance on NERC's website.[68] The FFT initiative illustrates that NERC continually reevaluates, redirects and rebalances its CMEP implementation efforts.

NERC developed FFT in conjunction with the Regional Entities. The development of the process benefited from collaboration with representatives of registered entities through a series of focus groups. During these focus group sessions, participants indicated that registered entities typically allocated time and resources equally among violations, regardless of the risk to reliability posed by each violation. Implementation of the FFT initiative was the first step towards addressing this mis-allocation of resources.

Since the launch of FFT in 2011, NERC has implemented additional enhancements to the process. Specifically, NERC expanded FFT treatment to: (i) a limited pool of possible moderate

[67] As noted previously, NERC will submit a separate informational filing to the Commission describing these processes.

[68] In contrast, NERC submits violations that pose a greater risk to reliability or do not otherwise meet the FFT criteria to the Commission in a spreadsheet Notice of Penalty (SNOP) or full Notice of Penalty (NOP) format.

risk violations; and (ii) some unmitigated possible violations so long as mitigation occurs within 90 days from the date the FFT item is filed or posted. To streamline processing of FFT items, NERC now posts FFTs collected by the Regional Entities on its website at the end of each month without prior review of such items. This replaces the prior procedure in which NERC submitted monthly informational filings to the Commission describing FFT items. While the Regional Entities post FFT items on a monthly basis, NERC maintains its enforcement oversight by reviewing a representative sample of FFTs during the 60-day window following the Regional Entities' monthly postings and by conducting an annual spot check of FFTs.

The FFT program has been highly successful in promoting a risk-based approach to resolving noncompliance. All Regional Entities utilize FFT to resolve a large number of minimal risk issues. Further, through its monthly reviews and annual spot checks, NERC verifies that the parameters for identifying minimal risk issues are consistently applied throughout the ERO Enterprise.

2. Reliability Assurance Initiative

In November 2012, NERC management proposed RAI as a multi-year effort to identify and implement changes to enhance the effectiveness of the ERO Enterprise's compliance and enforcement functions. RAI will help NERC foster consistency and efficiency in its compliance monitoring and enforcement processes. NERC expects RAI to improve BPS reliability by refocusing efforts on serious and substantial reliability risks and promoting the development and enhancement of the internal controls that mitigate those risks. Increased consistency in the ERO Enterprise's compliance and enforcement efforts yields a level of predictability for registered entities to understand how Reliability Standards are applied and enforced and to model positive behaviors.

To foster dialogue and seek industry feedback on the various aspects of RAI, NERC hosted a series of workshops in 2013 that addressed defining internal controls, conducting risk assessment, launching pilot programs, enhancing the FFT process, and improving self-reporting.

a. RAI Improvements to Compliance Monitoring Processes

The core concept of risk-based compliance monitoring is intended to guide Regional Entities in allocating resources for compliance monitoring activities and methods based on a registered entity's potential impact on the BPS. Compliance-related activities under the RAI program will help achieve a risk-based approach for compliance monitoring by evaluating current compliance monitoring practices, identifying improvements, and addressing the consistent application of audit techniques and the use of uniform tools to carry out compliance monitoring activities.

In 2013, NERC and the Regional Entities began to develop and implement tools that will define techniques and methods to perform compliance monitoring in a consistent manner across the ERO Enterprise. The Regional Entities began using the first of these tools, the *Compliance Auditor Checklist*, in August 2013. In December 2013, NERC and the Regional Entities completed the first draft of a companion document for the *Compliance Auditor Checklist*, specifically, the *Compliance Auditor Handbook*, as found in the *ERO Enterprise Compliance Auditor Manual* (Auditor Manual). NERC disseminated the Auditor Manual and provided initial training to Regional Entity auditors during the first quarter of 2014. In the second quarter of 2014, the Regional Entities began to use the Auditor Manual and its related processes and procedures on a select number of audits. Throughout 2014, NERC and the Regional Entities will revise and expand the Auditor Manual to address additional audit topics, reflect additional processes developed through RAI activities, and include lessons learned.

A second key RAI compliance activity, the Prototypes and Pilot program, focuses on the development and implementation of a formalized approach to risk assessments and testing of management controls. NERC and the Regional Entities initiated the first phase of the Prototypes and Pilot program during 2013. This phase explored different approaches to applying risk-based auditing concepts (e.g., audit scoping, reliability risk assessments, and management controls review and testing). For 2014 and beyond, a team consisting of NERC, Regional Entity, and industry representatives as well as an independent audit consultant will evaluate the findings and determine the best audit approach to implement throughout the ERO enterprise.

NERC and the Regional Entities are also developing and implementing activities that will address the transition to CIP Version 5 and redesign the tools and information available for compliance monitoring. In addition, and as discussed in further detail below, NERC and the Regional Entities have consolidated the annual CMEP Implementation Plans with the goal of implementing certain risk-based compliance enhancements.

b. RAI Improvements to Compliance Enforcement Processes

The enforcement aspect of the RAI builds on the success of FFT to develop incentives for registered entities to distinguish between poor performance and positive behaviors that contribute to higher accountability and improved reliability performance. The RAI calls for NERC to do the following by 2016: (i) exercise discretion to focus resources on the most serious and substantial risks to the reliability of the BPS; and (ii) empower registered entities to self-identify, mitigate and record noncompliance subject to NERC and Regional Entity oversight.

Similar to the RAI compliance monitoring effort, the enforcement element of RAI seeks to align the ERO's enforcement processing activities with levels of risk to the reliability of the BPS. Achieving this alignment will promote efficiencies for both the ERO Enterprise and

registered entities by eliminating undue regulatory burdens, streamlining documentation and filing requirements, and substantially improving the processing of noncompliance and related mitigating activities.

In 2013, NERC began implementing a series of activities in connection with RAI. These activities consisted of both short-term and long-term solutions to address registered entity concerns and improve enforcement processes. For example, in 2013, NERC and the Regional Entities developed the *ERO Self-Report User Guide*. This document explains the type and quality of information that a registered entity should submit with a self-report in order to allow for a prompt evaluation of noncompliance, and, if appropriate, a prompt disposition of the noncompliance if it poses a minimal risk to the reliability of the BPS. A companion *ERO Mitigation Plan Guide* document was also developed. NERC posted the draft guides in January 2014 for public review and comment. The final user guides are now available on the RAI page on the NERC website.[69]

Second, NERC and the Regional Entities began two pilot programs to test RAI enforcement concepts. The first pilot, the Aggregation of Minimal Risk Issues program, tests selected registered entities' ability to proactively self-address, identify, and mitigate minimal risk issues. The second pilot is testing the application of enforcement discretion; the purpose of this pilot is to identify minimal risk issues that would be recorded and mitigated without triggering an enforcement action. These pilot programs began a six-month testing cycle in October 2013. NERC and the Regional Entities are gradually expanding the programs to include additional registered entities.

[69] Available at: http://www.nerc.com/pa/comp/Pages/Reliability-Assurance-Initiative.aspx.

In addition, as of January 2014, all Registered Entities implemented the triage process. Under this process, all Regional Entities will review instances of noncompliance and make an initial determination as to whether an issue will proceed through enforcement or whether additional information is needed.

Going forward, NERC will continue to implement and evaluate these enforcement concepts. These processes will be further discussed in an informational filing on the RAI that NERC will submit to the Commission in 2014.

3. Development of a Consolidated CMEP Implementation Plan

NERC and the Regional Entities no longer create nine separate CMEP Implementation Plans, but rather have consolidated these documents into a single integrated CMEP Implementation Plan for the ERO Enterprise. The consolidated CMEP Implementation Plan uses a streamlined format that eliminates redundant information, improves the transparency of CMEP activities, and promotes consistency among the Regional Entities' Implementation Plans.

During the implementation year, NERC or a Regional Entity (with NERC approval) may update the Implementation Plan to change the *Actively Monitored List of Reliability Standards*, compliance monitoring processes, Regional Entity processes, or to provide updates. When updates occur, NERC will post a revised Implementation Plan to its website and issue a compliance communication. A Regional Entity may also update its Implementation Plan, with NERC approval. NERC is responsible for updating the ERO CMEP Implementation Plan to reflect any Regional Entity's changes and for posting the updated plan to its website and issuing compliance communications.

Following each implementation year, the Regional Entities will complete a CMEP Implementation survey due in January of the following implementation year (e.g., the 2014

CMEP Implementation Plan survey is due in January 2015). This survey will provide Regional Entity-specific information on compliance monitoring, outreach, enforcement, CMEP program effectiveness, and other regional activities. NERC will use this information to monitor Regional Entity CMEP implementation and to plan for the following implementation year.

4. Improvements in Processing of Compliance and Enforcement Items by NERC and the Regional Entities

a. NERC and the Regional Entities Have Improved the Speed and Efficiency of Processing Enforcement Items

During the assessment period, NERC and the Regional Entities have continued to hold industry accountable for violations that create serious risk to the BPS, and to implement improvements to ensure that enforcement actions are timely and transparent to industry. As discussed in further detail in the "Enforcement" section of the NERC Assessment of Regional Entity Delegated Functions (**Attachment 3**), by the end of 2013, NERC had reduced the number of active violations older than 24 months (excluding those held by appeal, a regulator, or a court)[70] so that only 65 such active violations remained. There has been consistent progress since 2012 in achieving the goal of processing all violations within 24 months following discovery.

By working to reduce the number of aging violations while improving the processing speed for newer violations, NERC and the Regional Entities reduced the average age of violations in the ERO caseload by six percent in 2013, from 11.86 months in 2012 to 11.2 months.

NERC's successes in improving the efficiency of violation processing can be attributed to several factors, including the implementation and use of streamlined enforcement processing

[70] "Held by appeal, a regulator or a court" (or "on hold") refers to violations that are not currently being processed by NERC or the Regional Entities as a result of a court or administrative proceeding that will impact the resolution of the violation.

mechanisms, such as FFT and the SNOP. The use of streamlined enforcement processing mechanisms has allowed NERC to increase substantially the number of violations filed in a given year, reducing the caseload and in turn, improving processing times.

In 2009 and 2010, NERC filed NOPs with the Commission for a combined total of 1,540 violations. In 2011, after implementing the use of streamlined enforcement processing mechanisms, NERC filed a total of 1,697 violations – more than the two previous years combined. In 2012, NERC filed a total of 1,767 violations. In 2013, NERC filed a total of 1,862 violations. NERC processed approximately 43 percent of the violations filed in 2013 using the FFT mechanism.

In addition to the use of streamlined enforcement mechanisms, NERC has dedicated substantial resources to improving its enforcement processing activities and performance. In fact, during the period covered by this *Five-Year ERO Performance Assessment Report,* NERC has more than doubled the size of its enforcement processing staff, going from four full time equivalent personnel (FTEs) in 2010 to nine FTEs as of January 1, 2014.

Lastly, NERC has taken several steps to enhance collaboration and consistency across the entire ERO Enterprise. NERC enforcement processing has assigned staff to work closely with each Regional Entity to enhance the relationships with each Regional Entity and to develop greater knowledge and expertise concerning each Regional Entity and identify areas for collaboration and process enhancement. In addition, NERC is continuing to provide training to the Regional Entities with the goal of increasing the consistency of enforcement processes and documents. Through collaboration with the Regional Entities, NERC expects to build on its past successes and continue to work toward reducing aging caseload, reducing enforcement processing times, and ensuring consistency in enforcement processes and procedures.

NERC and the Regional Entities have continued to work collaboratively to develop and implement a set of metrics to measure the efficiency with which enforcement items are processed. Development of these performance items was an area for improvement identified in the Commission's order on NERC's Three-Year ERO Performance Assessment.[71] A set of final metrics has been agreed upon and a set of common parameters was developed to ensure that metrics measurements by NERC and the Regional Entities remain consistent. To that end, in the third quarter of 2013, NERC and the Regional Entities developed a set of business rules to ensure integrity and alignment across NERC and Regional Entity data. Ensuring the integrity of this data is important for analyzing trends and calculating processing metrics.

The four metrics developed to monitor the performance of NERC and the Regional Entities in processing enforcement items are:

(1) Caseload Index – computes the number of months it would take to clear the violations in a Compliance Enforcement Authority's (CEA, i.e., NERC or a Regional Entity) inventory based on the CEA's average monthly processing rate for the preceding twelve month period;

(2) Violations in Inventory – reports the number of violations in the CEA's caseload;

(3) Violation Aging – reports, by Regional Entity, the number of violations discovered in each year beginning with 2007 that have not been filed with the Commission or otherwise resolved;[72] and

(4) Mitigation Activity Aging – identifies the status of mitigation activity based upon age of violations.

NERC will continue to analyze and evaluate violation processing data. The purpose of analyzing violations and violation processing information is to identify trends and emerging risks. This analysis will provide NERC with insight into the effectiveness of NERC's and the

[71] *Order on the Electric Reliability Organization's Three-Year Performance Assessment*, 132 FERC ¶ 61,217 (2010) at PP 138 and 217.

[72] NERC also monitors Violation Aging by Disposition Method. This includes the average turnaround time for each disposition method for violations discovered within a specified time horizon (i.e., discovery to date filed with NERC, date filed with NERC to date filed with the Commission, and discovery to date filed with the Commission).

Regional Entities' processes and programs. The analysis informs the development of enforcement policies and processes and offers feedback for other departments such as Standards.

NERC's departments collaborate to leverage analytics as a risk management and resource allocation tool. As an example of this effort, NERC is closely monitoring the status of mitigation activity completion, regardless of whether or not the violation is on hold. NERC aims to work with the Regional Entities to reduce the amount of time from discovery of a violation to completion of the mitigating activity, thereby reducing the ongoing risk that these violations may pose to reliability.

b. Oversight of Regional Entity Processes and Actions

NERC is continuously evaluating and improving its methods of overseeing the Regional Entities' implementation of CMEP processes and procedures. During the assessment period, NERC adopted a more methodical approach to evaluating Regional Entity performance with respect to enforcement activities. NERC has also enhanced its approach to evaluating Regional Entity compliance activities. These oversight activities ensure that the Regional Entities are meeting their obligations under the NERC ROP and the RDAs. These oversight activities also promote transparency and consistency, and drive the identification and implementation of best practices across the ERO Enterprise.

For additional information regarding NERC's oversight of Regional Entity enforcement program and processes, see the "Enforcement" section of the NERC Assessment of Regional Entity Delegated Functions, **Attachment 3** to this *Five-Year ERO Performance Assessment Report.*

c. Developing Common Compliance Auditor Qualifications Across the ERO Enterprise

NERC and the Regional Entities are developing common ERO auditor qualification

requirements and auditor job descriptions that will be consistently used across the ERO Enterprise. Establishing common ERO auditor qualifications is an initiative specified in the 2013-2016 ERO Strategic Plan.[73] NERC and the Regional Entities will establish key attributes and skill sets that audit team members should possess to ensure the audit team composition includes competencies needed to complete an effective audit. Establishing common ERO job descriptions promotes a consistent approach in attracting and retaining the necessary talent for auditor positions. Common auditor qualification criteria, training, and audit approach help promote high-quality audits and consistency in CMEP implementation activities across the ERO Enterprise.

d. Enhancing the Training Program for Auditors so that Processes and Procedures Developed in the RAI are Implemented Consistently Across the ERO Enterprise

As part of its Regional Entity Assurance and Oversight function, NERC is responsible for supporting the development of qualified and trained compliance operations and auditing staffs at both NERC and the Regional Entities. In addition to the development of a common set of auditor qualifications, described in the immediately preceding subsection, NERC ensures the proper qualifications of personnel for auditing and other essential compliance roles through training. As noted above, NERC and the Regional Entities collaborated to create the *Compliance Auditor Checklist* and *Compliance Auditor Handbook*, as found in the Auditor Manual.[74] These documents will be reviewed and revised to incorporate lessons learned from the RAI pilots. NERC will train auditors to ensure that Regional Entities are consistently applying the

[73] The *Electric Reliability Organization Enterprise Strategic Plan 2013-2016* is available at: http://www.nerc.com/gov/bot/FINANCE/Documents/ERO%20Enterprise%20Strategic%20Plan%202013-2016%20FINAL%2005%2009%2013.pdf

[74] Available at: http://www.nerc.com/pa/comp/ERO%20Enterprise%20Compliance%20Auditor%20Manual%20DL/ERO_Enterprise_Compliance_Auditor_Manual_version_1.pdf.

procedures and methodologies of these documents. Auditor training will also incorporate relevant changes related to enforcement processing, including changes to the self-reporting process and enhancements to the FFT process. Setting clear expectations for registered entities regarding audit practices and procedures should also allow registered entities to increase the efficiency and effectiveness of their pre-audit preparation.

D. Identification, Prioritization, and Dissemination of Information on Risks to the BPS

NERC is an expert resource for industry on reliability risks and information because it is uniquely positioned to assess potential impacts to reliability and raise awareness of threats to reliability. NERC draws upon a plethora of resources, discussed below, to make its assessments, including the RISC priorities, robust databases of information on transmission, generator and demand-response availability, the annual NERC *State of Reliability* report, and other assessments and reports, as well as internal core analyses of events. In its risk-informed approach, NERC uses performance analysis, solid technical foundation, sophisticated statistical analyses, and integrated validation with actual system events to enhance BPS reliability. As described in §II.D.1 below, at the direction of its Board of Trustees, NERC has developed and is implementing a specific RRM process to create and execute plans for managing reliability risks.

As an example of risk identification, NERC's *2013 Long-Term Reliability Assessment* (LTRA) identified significant emerging reliability issues that industry will face over the next decade.[75] These challenges stem from, among other things, a changing resource mix comprised of significant increases in variable energy resources to meet renewable portfolio standards, increased reliance on natural gas-fired generation and demand-side management primarily driven by economics, and the retirement of nearly 10% of North America's generation capacity.

[75] Available at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013_LTRA_FINAL.pdf.

Another resource for identifying and prioritizing risks is NERC's Event Analysis process. This process, which is described in greater detail in §II.D.3 below, establishes a systematic approach to capturing details about all BPS events, from minor Category 1 Events that typically do not have a significant impact on electricity users, to Category 4 and 5 Events that result in widespread customer outages.

Collectively, these resources provide an independent and complete picture of risks to reliability and key BPS reliability indicators such as resource adequacy, peak demand, energy forecasts and transmission developments. These efforts and well-developed resources are critical to how NERC approaches reliability, learns from events on the BPS, and prioritizes resources.

NERC draws upon these resources to inform industry and policymakers about trends and challenges to reliability. One example is the work of the NERC Integration of Variable Generation Task Force (IVGTF), which developed several recommendations that support the reliability considerations for accommodating large amounts of variable generation.[76] These recommendations guided the California Independent System Operator (CAISO) in finding solutions to how it will ensure reliability given the significant development of variable energy resources in that region of the country. Another example is the *Accommodating an Increased Dependence on Natural Gas for Electric Power* report that examined the different risks, arising out of the interdependence of the BPS and the natural gas delivery system, which can affect reliability.[77] Recommendations from this report are being used by WECC, the CAISO, and the Midcontinent Independent System Operator, among others, to identify approaches to minimize vulnerabilities due to electric system-gas system interdependence.

[76] Information about the IVGTF is available at: http://www.nerc.com/comm/PC/Pages/Integration-of-Variable-Generation-Task-Force-(IVGTF)-2013.aspx.

[77] Available at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_PhaseII_FINAL.pdf

1. Establishing a Structured Reliability Risk Management Process

In response to direction from the NERC Board in February 2013, NERC has developed a RRM process to create and execute plans for managing reliability risk and to integrate these plans with the business planning and budgeting process. The RRM process leverages: (i) the business acumen of the RISC; (ii) the technical knowledge of the NERC Operating Committee, Planning Committee, and CIP Committee (CIPC); (iii) the diverse set of tools that can be employed by the ERO to manage risk; and (iv) the open and transparent nature of the ERO. The RRM process is comprised of the following stages:

(1) Strategic Planning: In this phase, the RISC works to collection information and to identify broad areas of reliability risk to be recommended to the NERC Board for further analysis and study.

(2) Analysis: In this phase, members of the RISC work with the technical committees they represent to identify specific risks within the broad areas accepted by the NERC Board. This phase includes problem definition, gap analysis, and selection of measurement approaches.

(3) Solution Design: In this phase, members of the RISC develop potential solutions to the problems identified in the previous stage. NERC uses this information to develop the *ERO Top Priority Reliability Risks* for the upcoming business planning and budget cycle.

(4) Business Planning and Budgeting: In this phase, NERC staff and the Regional Entities work together to include in the annual business plans and budgets descriptions of the reliability risks that are to be addressed in the coming year and the resources needed to support those efforts.

(5) Preparation: In this phase, ERO staff, stakeholders, and third parties[78] discuss the plans identified in the latest business plan and budget. At this stage, NERC's committees have an opportunity to align their work plans with the business plan and budget.

(6) Execution: In this phase, stakeholders, staff, and third parties execute the detailed plans developed in the prior phase.

Specific documentation or other aids to assist in the implementation of the RRM

[78] "Third parties" in this context might refer to industry manufactures and service vendors, who might be asked to work on a specific problem, tool or application.

process,[79] document templates, and detailed instructions and training are being developed to support the execution of this process. NERC intends that the RRM process will become an integral part of ERO operations.

NERC will continue the work of the RISC to develop risk profiles (including HILF issues) for the ERO. These profiles of the BPS will inform how the ERO prioritizes and ranks reliability risks. For high priority risks, NERC will develop project plans and business case assessments outlining initiatives to address those risks.

2. ERO Top Priority Reliability Risks for 2014-2017

As described immediately above, the RRM process includes the identification of the *ERO Top Priority Reliability Risks* for each upcoming business planning and budget cycle. The development of the list of top ten high priority reliability risks is intended to focus the efforts of the ERO Enterprise program areas, including training and education, Reliability Standards development, and compliance. NERC developed a set of the ten top priority reliability risks to be focused on in the development of the *ERO Enterprise Strategic Plan 2014-2017*. The development of this list started with a reliability gap analysis that the RISC presented to the NERC Board in August 2013. NERC staff then undertook further review and analysis to identify any additional reliability risk areas of strategic importance for the ERO. Next, qualitative estimates of probability, consequence, and current level of risk management were prepared for each of the identified reliability risks within the chosen areas. NERC used this information to identify ten top priority reliability risks requiring increased attention or additional activity. Following this analysis, recommendations were developed based on previous committee discussions; industry dialogue at the Reliability Leadership Summit; and past work products such

[79] This documentation and other aids may include worksheets, diagrams, task descriptions, and similar items.

as the LTRA, the *State of Reliability* report, and various special reports and assessments. The ten high priority reliability risks are:

(1) Changing Resource Mix: As the generation and load on the power system changes (e.g., integrated variable resources, increased dependence on natural gas, increased demand-side management, new technologies deployed), the system is being brought into states that are significantly different than those considered when the system was designed and planned, exposing new vulnerabilities not previously considered. Fundamental operating characteristics and behaviors are no longer a certainty.

(2) Resource Planning: Plant retirements (largely due to implemented environmental regulations; increased uncertainty in future resources due to other potential environmental regulations; and lower natural gas prices, which significantly affect power plant economics) are leading to cases where resources may be inadequate to ensure firm demand is served at all times. As the system continues to change, some regional assessments identify concerns with insufficient reserve margins as early as 2014 and 2015 in the ERCOT and Midcontinent ISOs.

(3) Protection System Reliability: A fault accompanied by a failure of any protection system component could in some cases result in instability, violation of applicable thermal or voltage ratings, unplanned or uncontrolled loss of demand or curtailment of firm transfers, or cascading outages.

(4) Uncoordinated Protection Systems: A lack of protection system coordination has the potential to increase the size and magnitude of events due to unnecessary trips. Uncoordinated protection systems were identified as contributing to the September 8, 2011, and August 14, 2003 events.

(5) Extreme Physical Events: While the probability of extreme physical events (such as physical attack, GMD, or severe weather) that lead to extensive damage is low, the potential consequences are significant enough that risk avoidance (reducing the probability) is insufficient as a sole risk management strategy.[80]

(6) Availability of Real-Time Tools and Monitoring: Not having the right tools and monitoring available to manage reliability in real time is a latent problem waiting for the right combination of events to exploit it.

(7) Protection System Misoperations: NERC's 2012 and 2013 *State of Reliability* reports identified protection system misoperations as a significant threat to BPS reliability.

(8) Cold Weather Preparedness: Lack of generator preparedness for cold weather extremes may result in forced outages, de-ratings, and failures to start.

[80] Additional strategies may incorporate factors like improving resiliency and reducing restoration times.

Insufficient availability of intra-regional generation and limits on import transfer capability may result in insufficient generation to serve forecasted load, resulting in load shedding.

(9) Right-of-Way Clearances: Transmission owners and applicable generation owners may have established incorrect ratings based on design documents, rather than on the actual facilities built. Managing to stay within system operating limits and interconnection reliability operating limits that are based on incorrect ratings may be inadequate to prevent equipment damage and/or instability, cascading outages, or separation. Ensuring clear right-of-ways can reduce adverse impacts to reliability even when SOLs and IROLs are based on incorrect ratings.

(10) 345-kV Breaker Failures: NERC has identified a potential trend of 345 kV SF6 puffer type breakers failing. Circuit breaker failures, in conjunction with another fault, may lead to more BES facilities removed from service than required to clear the original fault.

3. NERC Event Analysis Process and How it is Used to Identify Risks to the BPS and Disseminate Lessons Learned

NERC has developed a voluntary Event Analysis process that delivers quality, timely and actionable lessons learned to registered entities. Development of the Event Analysis process was led by the Event Analysis Subcommittee (EAS), a cross-functional group of industry experts.[81]

The Event Analysis process begins with a registered entity making an initial assessment of an occurrence and determining if the occurrence falls within one of five qualifying event categories.[82] The event category is determined by weighing the level of significance of a qualifying event and its impact on the interconnected BPS. After a qualifying event occurs, the applicable Regional Entity holds a planning meeting with all involved parties, including other registered entities. If a qualifying event is categorized as Category 3 or higher, the registered entity will prepare an Event Analysis Report (EAR), in which the registered entity describes the

[81] The EAS is a subcommittee of the NERC Operating Committee.

[82] A description of each event category is included in the *Electric Reliability Organization Event Analysis Process – Version 2* report, available at: http://www.nerc.com/pa/rrm/ea/Pages/EA-Program.aspx.

sequence of events and identifies causal factors and appropriate corrective actions. The registered entity then submits the EAR to the applicable Regional Entity(ies) for review, and then to NERC. The registered entity, in collaboration with the ERO, drafts the proposed lessons learned from the event and submits them to the applicable Regional Entity. Once the event analysis is complete, NERC shares any lessons learned with industry by publishing them as soon as practical. NERC staff analyzes EARs to identify reliability risks, trends, and potential gaps in Reliability Standards, compliance, and other programs. NERC also reviews the EARs to assign descriptive cause codes, which assist in identifying trends and corrective actions that will prevent recurrence of similar events.

Since initial implementation of the Event Analysis process in 2010, there have been more than 388 qualified events reported to the ERO and more than 77 lessons learned produced, including 14 published in 2013.

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Event Counts

Event Category	Count (Total)	Count (2013)	Comments
CAT 1	256	91	
CAT 2	114	33	
CAT 3	14	6	
CAT 4	3	0	SW Winter Weather (2011) SW Blackout (2011) Derecho (2012)
CAT 5	1	0	Hurricane Sandy (2012)
Total CAT 1-5 Events	**388**	**130**	
Non-Qualified Occurrences reported	**1711**	**338**	

RELIABILITY | ACCOUNTABILITY

Participation in the voluntary Event Analysis process does not relieve registered entities of their obligation to comply with NERC Reliability Standards. While performing the steps of the Event Analysis process, the registered entity is encouraged to continue performing critical self-assessments of compliance with Reliability Standards in connection with the event and to conduct compliance self-assessments for review by applicable Regional Entities. If a registered entity discovers a possible violation in the process of analyzing an event, it is encouraged to self-report that possible violation to the applicable Regional Entity.

NERC is continuously improving how it defines, catalogs and trends the causes of system events. NERC assesses every event submitted through the voluntary Event Analysis process to identify and share possible risks to reliability with industry. Further, the cause code assignment allows for greater historical trending and predictive analysis.

NERC provides Regional Entity and registered entity staff with cause analysis training. As of December 2013, 164 personnel from all eight Regional Entities and over 600 people from 115 different registered entities have received more than 4,000 hours of cause analysis training, with 432 hours of continuing education hours awarded to 54 NERC-certified system operators in connection with this training. NERC is adding a training and education component to the Event Analysis process to increase the relevance and impact of lessons learned for the Regional Entities, industry, and other stakeholders. Through the Event Analysis process, NERC continues to establish the appropriate balance of data reporting for analysis and use by industry.

NERC continues to work with the Regional Entities to obtain from and review with registered entities information regarding qualifying events and disturbances. The primary goal of this process is to identify reliability risks through robust data gathering, validation, rigorous analysis, and rapid dissemination to industry of information on identified risks and remediation

options. NERC is working collaboratively with the Regional Entities to prioritize analytical efforts based on the Event Analysis process categories. Determining root and contributing causes for each event allows for trend and risk identification. NERC plans to further facilitate event analysis by merging its event-driven databases and defining the relationships between various system cause codes. This analysis of system events will inform NERC of gaps in Reliability Standards, compliance monitoring and enforcement effectiveness, registration, and risk controls effectiveness.

Additionally, NERC is collaborating with the North American Transmission Forum and the North American Generator Forum to further enhance the Event Analysis process and lessons learned dissemination in identifying risks to the BPS. Further, NERC plans to improve the timeliness of the availability of and access to final event reports by creating a secure portal that will be accessible by industry to obtain these reports.

4. Reports on Reliability

In May 2012, NERC released its first *State of Reliability* report assessing grid reliability based on performance trends identified through data and analysis of system disturbance events. The report presented NERC's integrated view of ongoing BPS reliability and performance trends. It assessed 18 reliability performance metrics that measure whether an adequate level of reliability exists in North America. The report also included an analysis from the frequency response initiative, the 2011 demand response availability assessment, event analysis trends, and post-seasonal assessments. The initial *State of Reliability* report included the following key findings:

(1) Reliability of the BPS remains adequate with little change in trends between 2008 and 2011;

(2) Frequency response is stable with no deterioration;

(3) Protection system misoperations are a significant reliability issue;

(4) Equipment failure warrants further analysis; and

(5) Resource mix changes necessitate new metrics.

Subsequently, *State of Reliability* reports have been issued for 2013 and 2014.[83] Going forward, NERC will continue to prepare its annual *State of Reliability* report and the associated reliability metrics.

As noted earlier, for many years NERC has prepared and issued an annual 10-year LTRA Report for the North American BPS. The LTRA provides an independent view of the reliability of the BPS and identifies trends, emerging issues, and potential concerns. Recent LTRAs have focused on a variety of emerging issues expected to impact BPS reliability. Most notably, a rapidly changing resource mix with substantial retirements of coal-fired and nuclear capacity, paralleled by a growing reliance on natural gas-fired generation that has created fuel transportation concerns in certain areas. Ongoing unit retirements are also contributing to diminishing reserve margins that fall below reference reserve margin levels during the 10-year outlook. Finally, continued penetration of variable resources and a growing dependence on demand-side management programs create uncertainties for system planners and operators. Each LTRA report also provides high-level recommendations for each emerging issue and tracks ongoing industry progress.

In addition to the annual LTRA, NERC issues two seasonal (i.e., summer and winter) assessment reports each year in which it identifies, assesses, and reports on the industry's preparations to manage potential seasonal issues such as significant generation or transmission

[83] NERC's *State of Reliability 2014* report is available at: http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2014_SOR_Final.pdf.

constraints or potential fuel-related impacts. NERC also issues other, special reports from time to time that focus on current or emerging technical or other reliability concerns, such as changing resource mix (increasing amounts of variable generation and potential retirements of fossil-fueled generation), misoperations, HILF event concerns, and smart grid considerations.

NERC has implemented several enhancements to the LTRA processes and reports in response to areas for improvement identified in the three-year ERO performance assessment. NERC has revised its reliability assessment guidelines to establish a requirement for an annual scenario analysis.[84] Scenario analyses are typically included in separate special assessments prepared by the Reliability Assessment program, including the following reports that NERC issued during the assessment period:

- *Reliability Impacts of Climate Change Initiatives: Technology Assessment and Scenario Development* (2010);
- *Special Reliability Scenario Assessment: Potential Reliability Impacts of Swift Demand Growth After a Long-Term Recession* (2010);
- *Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations* (2010);
- *Potential Impacts of Future Environmental Regulations* (2011); and
- *Special Reliability Assessment: Accommodating an Increased Dependence on Natural Gas for Electric Power* (2013).

5. Bulk Power System Awareness Department

Previously a functional responsibility of the Electricity Sector Information Sharing and Analysis Center (ES-ISAC),[85] NERC created the Bulk Power System Awareness department

[84] *See Order on the Electric Reliability Organization's Three-Year Performance Assessment*, 132 FERC ¶ 61,217 (2010), at P 180.

[85] The activities of ES-ISAC are described in §II.E.2 below.

(BPSA) in 2012 to improve NERC's capability to monitor BPS conditions, significant events, and emerging risks to reliability across the 15 reliability coordinator regions in North America.

BPSA develops and disseminates timely, accurate and complete information regarding the status of the BPS from a near-term operational reliability perspective, complementary to RAPA's seasonal and long-term assessments and ES-ISAC's cyber and physical security perspective. BPSA shares this continuous assessment across NERC, the eight Regional Entities and FERC staff through a number of channels, including a *System Awareness Daily Report* that highlights current day potential risks to wide-area reliability, significant operational and security occurrences for the previous day, and high-level information on forecasted loads and reserves.

During major system disturbances, BPSA facilitates information sharing and a common operational picture of BPS status with a broader audience of industry and governmental agencies. BPSA provides ES-ISAC operational reliability information in support of its government and cross-sector coordination activities, and hosts periodic update conference calls for technically oriented government agencies including FERC, the Department of Energy, the Nuclear Regulatory Commission, the Department of Homeland Security, and the Federal Emergency Management Agency.

BPSA administers the NERC Alerts program, which is used to disseminate important reliability and security information to industry, pursuant to §810 of the NERC ROP. Additionally, BPSA actively participates in the Event Analysis Process described in §II.D.3 above, by identifying qualifying events and other items of interest for further trending and analysis.

E. The ERO Facilitates Information Sharing on Cybersecurity and Cyber and Physical Threats to the BPS among Industry, Regional Entities, and Government

Section 215(a) of the FPA and the Commission's regulations at 18 C.F.R. §39.1 define "reliable operation" of the BPS as "operating the elements of the Bulk-Power System within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a Cybersecurity Incident, or unanticipated failure of system elements." The FPA and the regulations define "Cybersecurity Incident" as "a malicious act or suspicious event that disrupts, or was an attempt to disrupt, the operation of those programmatic electronic devices and communications networks including hardware, software and data that are essential to the Reliable Operation of the Bulk-Power System." As the Commission is fully aware, identifying, assessing, and preventing threats and risks to both the physical security and the cybersecurity of the BPS, while always matters of concern, have attained increasing significance in the last three to four years.

Two of NERC's principal programs focused on these areas are the Critical Infrastructure department (CID) and the ES-ISAC. The CID supports efforts to develop and administer critical infrastructure standards, conducts security and reliability outreach visits, provides training and exercise opportunities, and coordinates between industry and governmental entities on CIP matters. The CID accomplishes these activities through active CIP standards drafting team participation, and programs such as the Sufficiency Review Program (SRP),[86] the annual Grid Security Conference (GridSecCon), and the biennial Grid Security Exercise (GridEx). The CID also leverages public-private partnerships to examine CIP policy issues, and it provides staff-

[86] In 2014, CID renamed the SRP to "Security Readiness Program" to reflect the program's focus.

level support to NERC's CIPC, an industry-led committee comprised of industry experts in the areas of cybersecurity, physical security, and operational security. The ES-ISAC monitors the physical security and cybersecurity of the electricity sub-sector, gathers information on threats to the physical security and cybersecurity of the sub-sector, and actively disseminates information on such threats and means to avoid or mitigate them to users, owners, and operators of the BPS as well as to applicable government entities and other stakeholders.

Both programs focus significant attention on public-private partnerships, which are critical to effective information sharing. CID and the ES-ISAC work closely with NERC entities, industry trade associations, national and international government departments and agencies, and other sectors to share information, discuss sector priorities, and respond to legislative and executive branch requests. Recent partnership activity includes sector responses to Executive Order (EO) 13636, *Improving Critical Infrastructure Cybersecurity*, and Presidential Policy Directive (PPD) 21, *Critical Infrastructure Security and Resilience*. This work included coordinating with government and across sectors to develop a voluntary cybersecurity framework, based on existing standards, guidelines, and practices, for reducing cyber risks to critical infrastructure. In addition, NERC worked closely with government and industry to rewrite the *National Infrastructure Protection Plan*, which outlines how government and private sector participants in the critical infrastructure community work together to manage risks and achieve security and resilience outcomes.

This section of this *Five-Year ERO Performance Assessment Report* describes NERC's activities in these areas during the assessment period, with an emphasis on activities during the latter part of the period. Included in this section are descriptions of CID programs, such as the

CIPC, the SRP, the GridSecCon, and the GridEx, as well as ES-ISAC activities, including the Cyber Risk Preparedness Assessment (CRPA) program.

1. Critical Infrastructure Department Activities

a. Critical Infrastructure Protection Committee

NERC's CIPC focuses on advancing the physical and cybersecurity of the critical electricity infrastructure of North America. The committee consists of both NERC–appointed regional representatives and technical subject matter experts. The CIPC coordinates NERC's security initiatives and serves as an expert advisory panel to the NERC Board, to the ES-ISAC, and to NERC standing committees, in the areas of cybersecurity and physical security. During quarterly CIPC meetings, CIPC members receive security training and participate in briefings regarding the latest security issues. To address issues related to cybersecurity and physical security, the CIPC establishes working groups or task forces comprised of subject matter experts who review and examine specific issues and develop reports and recommendations.

In 2012, the CIPC reorganized and expanded to allow it to produce more deliverables. This reorganization established new subcommittees and created new task forces and working groups to address emerging issues and initiative requests from the NERC CEO and NERC Board. The reorganization included forming task forces to address cybersecurity-related subjects identified in the 2010 *High-Impact, Low-Frequency Event Risk to the North American Bulk Power System* report.[87] One CIPC task force, the Cyber Attack Task Force, considered the impact of a coordinated cyber-attack on the BPS and developed flexible options for detecting, operating, and recovering from such an attack. A key component of the resulting Cyber Attack

[87] Available at: http://www.nerc.com/pa/ci/resources/documents/hilf_report.pdf.

Task Force report was the development and use of an attack tree tool that provides key insight into the attack surface of the interconnected BPS of North America.

Following NERC Board approval of the Cyber Attack Task Force report, the CIPC established a High-Impact, Low-Frequency Implementation Task Force to review the recommendations in this and other related reports, and to determine which recommendations the CIPC should address. The High-Impact, Low-Frequency Implementation Task Force determined that the CIPC should continue its analysis of cyber attack trees and analyze issues relating to information sharing, security clearances, security metrics, and physical security guidelines. The CIPC established task forces for all of these issue areas, and most groups have completed their reviews and issued recommendations.

b. Security Readiness Program

NERC conducts SRP visits, which consist of visits to registered entities to focus on the sufficiency of industry implementation of the CIP Standards. An SRP visit both examines CIP Version 3 compliance in a retrospective review and helps registered entities address transitioning from CIP Version 3 to CIP Version 5 in a prospective view. While compliance with CIP Version 3 and its risk-based assessment methodology remains mandatory until March 31, 2016, many registered entities are concerned about how to transition their compliance and security efforts to Version 5 to meet the April 1, 2016, compliance deadline. Registered entities are exploring how to best manage the transition process to CIP Version 5 while remaining compliant with CIP Version 3. NERC invites Regional Entity representatives to participate in SRP discussions; however, no content from those discussions may be used during a subsequent audit or compliance action unless that content reveals an imminent threat to the BES. NERC staff,

Regional Entity representatives, and outside consultants sign non-disclosure agreements to ensure strict confidentiality of all discussions and materials.

c. Grid Security Conferences

In 2011, NERC hosted the first GridSecCon focusing on physical security and cybersecurity issues facing the electricity sub-sector. NERC has continued to hold these conferences annually to achieve the following objectives:

- Build on NERC's mission to ensure the reliability of the North American BPS through education and training;
- Discuss and provide solutions to emerging industrial control system security issues;
- Deliver expert analysis on social engineering and phishing attacks;
- Focus strategically on public-private partnerships; and
- Provide an update on ES-ISAC activities and issue a call for increased industry participation and communication.

Over 300 industry and government stakeholders attended the most recent GridSecCon in October 2013. More than 20 speakers led discussions focused on industry being transformational, strategic, and tactical in its approach to securing systems. Participants were asked to consider different information sharing techniques; determine if their organizations are resilient through self-assessments; test response activities through exercises; work to ensure that security is built into operations; and enhance the workforce by recruiting, training, and retaining individuals who can address these and other issues. Additionally, almost 200 stakeholders attended credentialed training sessions in cybersecurity and physical security.

d. Grid Security Exercises

In 2011, NERC hosted the first GridEx, which focused on analyzing industry's response to a physical and cybersecurity scenario. NERC now holds a biennial distributed play exercise and executive tabletop discussion to achieve the following:

- Exercise the current readiness of the electricity industry to respond to a security incident, incorporating lessons learned;
- Review existing command, control, and communication plans and tools for NERC and its stakeholders;
- Identify potential improvements in cybersecurity and physical security plans, programs, and responder skills; and
- Explore senior leadership policy decisions and triggers in response to a coordinated cyber and physical event of national significance with long-term grid reliability issues.

Over 200 organizations participated in GridEx II, which took place November 13, 2014 through November 14, 2013. During the exercise, participants identified five key lessons learned:

- Information sharing has increased;
- NERC has improved ES-ISAC and BPSA coordination functions;
- Simultaneous cyber and physical attacks pose significant challenges;
- Industry continues to refine and enhance its all-hazard incidence response plans and protocols; and
- Industry and government information-sharing stakeholders can better inform incident response through coordination and consolidation of content.

GridEx II included an executive tabletop exercise involving about 30 participants, including electricity industry executives representing a broad cross-section of the industry and senior officials from the federal government. Participants considered a severe cyber and physical

attack scenario of national and international significance, and discussed the policy-level challenges that would need to be addressed by industry and government.

e. Electricity Sub-sector Coordinating Council

NERC established the Electricity Sub-sector Coordinating Council (ESCC) in 1998 at the request of the Department of Energy to foster and facilitate the coordination of sector-wide, policy-related activities and initiatives designed to improve the reliability and resilience of the Electricity Sub-sector, including physical and cyber infrastructure. In 2010, NERC restructured the ESCC to consist of industry senior executives with NERC's CEO as the ESCC chair. The ESCC provided advice to the NERC Board on policy-level matters related to critical infrastructure, developed a Critical Infrastructure Strategic Roadmap, and provided oversight on several NERC and industry initiatives to address HILF events and other critical infrastructure risks to the BPS.

In August 2013, the NERC Board approved a new ESCC charter, which amended, superseded, and terminated the existing charter. The new charter provides for a total of 30 CEO-level representatives, including members of the ESCC Steering Committee. NERC's CEO continues to serve on the ESCC and its Steering Committee. The transition formally recognized the significant increased CEO interest and participation on cybersecurity issues, focused industry association activities through an existing channel recognized by government agencies, and provided a unified industry framework upon which to build in response to President-issued orders and directives, such as EO-13636 and PPD-21.

2. ES-ISAC Tools and Activities

a. ES-ISAC Portal

The ES-ISAC has seen a tremendous leap in its user base since its inception in 1998, with

more reporting from organizations and more information sharing between members of industry. The ES-ISAC portal, which became functional in April 2012, is the industry's first and often primary interface with the ES-ISAC. The portal is continuously updated with technical and trend reports, watch lists, advanced sector information sharing tools, and other relevant resources. The portal receives "Indicators of Compromise" from various sources, including U.S. government departments and agencies, and NERC distributes this information to electricity sector entities. The portal allows the ES-ISAC to reach thousands of users and hundreds of organizations across industry to discuss and exchange security-related information. The ES-ISAC is concentrating its efforts on increasing the user base of this important portal. The success of this effort relies on the value of information available on the portal as well as the timeliness with which information reaches users. To achieve this goal, the ES-ISAC is enhancing portal capabilities to improve the ease of use and to improve analytic collaboration across the sub-sector.

Current capabilities of the portal include publishing alerts and other informational products, exchanging threat indicator information, and providing self-service access to portal users. Upgrades underway will increase flexibility to support additional functionality and capacity using a cloud-based, secure platform solution. The improved portal will facilitate direct data exchange with other ISACs and government partners. The portal will also support ES-ISAC analysts in their information analysis functions and tie the ES-ISAC analysts together with their counterparts in other sectors and in national laboratories. Finally, the portal will add private social media information sharing tools, automated access to enhanced cybersecurity information flows, and predictive analytics.

b. Analytics

The ES-ISAC has also improved its analytic capabilities by building out its operations

room to include data feeds from multiple sources, such as NERC's situation awareness monitoring tool, and procuring services that deliver cyber awareness information. As a result, the ES-ISAC is uniquely positioned to enhance grid and sector-level resilience by quickly evaluating and addressing potential cybersecurity impacts to BPS operations.

c. Industry and Government Coordination

The ES-ISAC was initiated to gather information from industry participants about security-related events, disturbances, and off-normal occurrences in the electricity sub-sector. The ES-ISAC shares that information with industry as a whole and with government partners. In turn, government entities provide information regarding risks, threats, and warnings to the ES-ISAC. The ES-ISAC adds analytic value to shared information and coordinates with other sectors. It is also responsible for developing industry and government products, including the NERC crisis action plan and the U.S. Department of Homeland Security incident response analysis. In addition, the ES-ISAC co-hosts annual cleared briefings to industry to ensure the electricity sub-sector maintains awareness of new and ongoing threats to the BPS.

Most recently, the ES-ISAC collaborated with the Department of Homeland Security, the Department of Energy, and the Federal Bureau of Investigation to host a series of briefings focused on tactics and tools of emerging cyber threat actors. In addition, in the wake of the April 16, 2013 Metcalf substation incident in California, the ES-ISAC worked with these agencies and other organizations and governmental partners to raise awareness of physical attack threats, to increase local, regional and federal security partnerships, and to support mitigation efforts. These briefings continued through the first quarter of 2014.

d. Cyber Risk Preparedness Assessments

The ES-ISAC conducts CRPAs to assess the cybersecurity capabilities of registered

entities through facilitated tabletop exercises. Conducting these assessments allows the ES-ISAC staff to gain a better understanding of industry capabilities, identify key sector level areas for improvement, and share best practices across industry. Through CRPA exercises, participants gain an improved understanding of their cybersecurity programs and capabilities. These exercises also help participants identify areas for improvement and enhance their abilities to respond to and recover from cybersecurity events. The CRPA also educates participants through defined deliverables and best practices. During 2013, the ES-ISAC incorporated elements of the Electricity Sub-sector Cybersecurity Capability Maturity Model program into the CRPA. Additionally, the ES-ISAC has developed a CRPA kit for entities to use in developing and running their own CRPAs. The kit allows more entities to leverage the CRPA methodology to enhance their preparedness. In February 2013, ES-ISAC staff hosted initial training and education sessions on the kit to accelerate adoption of the methodology across the sector and move the program towards self-sustainment within industry.

III. NERC CONTINUES TO MEET THE §39.3(b) CRITERIA

An explicit requirement for the five-year ERO performance assessment is that it include an explanation of how the ERO satisfies the requirements of 18 C.F.R. §39.3(b). Section 39.3(b) sets forth the requirements for certification as the ERO, which specify that the entity:

(1) Has the ability to develop and enforce, subject to 18 C.F.R. §39.7, Reliability Standards that provide for an adequate level of reliability of the BPS;[88] and

(2) Has established rules that:

(a) Assure its independence from users, owners and operators of the BPS while assuring fair stakeholder representation in the selection of its directors and balanced decisionmaking in any ERO committee or subordinate organizational structure;

[88] 18 C.F.R. §39.7 sets forth the Commission's regulations concerning the enforcement of Reliability Standards by the ERO, including provisions pertaining to the imposition of penalties for violations of Reliability Standards.

(b) Allocate equitably reasonable dues, fees, and charges among end users for all activities under Part 39;

(c) Provide fair and impartial procedures for enforcement of Reliability Standards through the imposition of penalties in accordance with 18 C.F.R. §39.7, including limitations on activities, functions, operations, or other appropriate sanctions or penalties;

(d) Provide reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing Reliability Standards and otherwise exercising its duties; and

(e) Provide appropriate steps to gain recognition in Canada and Mexico.

Attachment 1 to this *Five-Year ERO Performance Assessment Report* shows in detail that NERC continues to satisfy the requirements of §39.3(b).

With respect to the requirements of §39.3(b)(1), NERC continues to have the ability to develop and enforce, subject to 18 C.F.R. §39.7, Reliability Standards that provide for an adequate level of reliability of the BPS. This requirement encompasses two distinct functions of the ERO: (i) the ability to develop reliability Standards that provide for an adequate level of reliability of the BPS, and (ii) the ability to enforce those Reliability Standards. NERC develops Reliability Standards pursuant to §300 of its ROP and its SPM, Appendix 3A to the ROP. These documents have been revised since NERC was certified as the ERO, including during the current assessment period, and the current versions of §300 and Appendix 3A have been approved by the Commission as ERO Rules. Further, NERC's SPM has been accredited by the ANSI as meeting ANSI's essential requirements for standards development. Moreover, as shown in detail in **Attachment 1**, NERC's Reliability Standards development process contains the essential attributes of the standards development process as set forth in prior Commission orders. As noted, during this assessment period, NERC has made improvements to its SPM, which the Commission has approved.

Further, NERC systematically manages the development of new Reliability Standards

and revisions to standards, in areas of highest need and importance, through its rolling three-year RSDP. The RSDP is revised annually and identifies and prioritizes Reliability Standards development projects in the immediate three-year time horizon, taking into account, among other information, perceived gaps in the Reliability Standards, proposals for closing those gaps, and timing priorities for standards development projects.

NERC enforces compliance with approved Reliability Standards through its CMEP, which is embodied in §400 and Appendix 4C of the ROP; its Organization Registration and Certification Program, which is embodied in §500 and Appendices 5A and 5B of the ROP; and its *Sanction Guidelines*, Appendix 4B of the ROP (all of the foregoing have been approved by the Commission as ERO Rules), as well as through its RDAs with the Regional Entities, which have also been approved by the Commission. Through the organization registration provisions of its ROP, NERC and the Regional Entities identify the users, owners, and operators of the BPS that are obligated to comply with Commission-approved Reliability Standards.

Monitoring and enforcement of compliance with Reliability Standards is conducted primarily by the eight Regional Entities pursuant to §401.4 of the ROP and the RDAs, subject to NERC oversight. Provisions of the ROP describe in detail the required attributes of Regional Entity compliance programs, including compliance program structure, resources and design. The controlling document for NERC's compliance monitoring and enforcement activities is the *Compliance Monitoring and Enforcement Program*, Appendix 4C to the ROP. Appendix 4C specifies compliance monitoring methods to be used and the detailed process steps for each method. Additionally, Appendix 4C specifies the process steps to be followed when a potential violation of a Reliability Standard by a registered entity is identified; as well as the actions required of the registered entity if it is found to be in violation of a Reliability Standard. The

Sanction Guidelines, which were significantly revised during this assessment period, specify the factors to be taken into account by the ERO in determining the financial penalty to be assessed for a violation of a Reliability Standard.

Pursuant to the RDAs, each Regional Entity has either adopted the NERC CMEP or a modified version of the CMEP as its compliance monitoring and enforcement program. Compliance monitoring and enforcement activities are further guided by the annual NERC and Regional Entity CMEP Implementation Plans (as described earlier, now combined into a single annual CMEP Implementation Plan document).

As detailed in **Attachment 1**, over this assessment period, NERC and the Regional Entities have continued to increase the resources devoted to compliance monitoring and enforcement activities. In their approved business plans and budgets for 2009, NERC and the Regional Entities provided for, collectively, 158.25 FTE staff and approximately $32.5 million of direct expenditures in their CMEPs. In their business plans and budgets for 2014, NERC and the Regional Entities provided for, collectively, 303.40 FTE staff and approximately $57.1 million of direct expenditures in their CMEPs.

With respect to the requirements of §39.3(b)(2)(i), NERC continues to have in place rules that assure its independence from users, owners, and operators of the BPS while assuring fair stakeholder representation in the selection of its directors and balanced decision-making in any ERO committee or subordinate organizational structure. This criterion encompasses three distinct considerations: (i) independence of NERC from users, owners and operators of the BPS; (ii) fair stakeholder representation in the selection of NERC's directors (i.e., its trustees); and (iii) provision for balanced decision-making in any NERC committee or organizational structure.

As described in detail in **Attachment 1**, provisions of NERC's Commission-approved Bylaws,[89] along with several NERC policy documents[90] assures NERC's independence from users, owners, and operators of the BPS. Provisions of the NERC Bylaws also assure fair stakeholder representation in the selection of NERC's trustees. Finally, provisions of the NERC Bylaws and of §1300 of the ROP specify requirements for selection of members for and voting procedures on, NERC committees and sub-groups, that provide for balanced decision-making.

With respect to the requirements of §39.3(b)(2)(ii), NERC's Bylaws and §1102 of its ROP provide for equitable allocation of reasonable dues, fees and charges among end users for all of the ERO's statutory activities. Section 1102 provides for the assessments to recover NERC's approved funding requirements to be allocated among countries, regions, and load-serving entities in the North American BPS based on Net Energy for Load (NEL), except where direct assignment of costs to a specific country or region(s) is appropriate. The NEL-based allocation of the annual assessments to cover NERC's and the Regional Entities' annual funding requirements is provided to the Commission for approval in NERC's annual business plan and budget filing.

With respect to the requirements of §39.3(b)(2)(iii), NERC's rules also continue to provide fair and impartial procedures for enforcement of Reliability Standards through the imposition of penalties in accordance with 18 C.F.R. §39.7. These rules and procedures include §400 of the ROP; Appendix 4B, *Sanction Guidelines*, of the ROP; and Appendix 4C, the *Compliance Monitoring and Enforcement Program*, of the ROP, which includes the Hearing

[89] NERC's Bylaws are considered "ERO Rules." 18 C.F.R. §39.1.

[90] NERC's *Governance Guidelines* is available at: http://www.nerc.com/gov/Annual%20Reports/Governance%20Guidelines%20-%20Approved%202.6.14.pdf; NERC's *Employee Code of Conduct* is available at*:* http://www.nerc.com/gov/Annual%20Reports/Employee-Code-of-Conduct.pdf; and NERC's *Policy on Reporting Complaints Regarding Accounting and Code of Conduct Matters*, is available at: http://www.nerc.com/gov/Annual%20Reports/Whistleblower_Policy_Final-May%202014.pdf.

Procedures to be followed by Regional Entity Hearing Bodies in presiding over and ruling on disputes raised by a registered entity with respect to a Regional Entity's proposed finding of a violation or the proposed amount of penalty for a violation. All of these provisions have been approved by the Commission as ERO Rules. All of these provisions have been extensively revised, and the revisions approved by the Commission, during this assessment period. **Attachment 1** to this report describes in detail NERC's rules and procedures for the determination and imposition of penalties for violations of Reliability Standards and how they comply with the requirements of §215(e)(6) of the FPA and §39.3(b)(2)(iii) and §39.7 of the Commission's regulations.

With respect to the requirements of §39.3(b)(2)(iv), NERC continues to maintain rules that provide reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing Reliability Standards and otherwise exercising its duties. NERC's Bylaws require that Reliability Standards be developed through an open, transparent, and public process that provides for reasonable notice and opportunity for public comment, due process, and balancing of interests; and that participation in the Reliability Standards development process shall not be limited to NERC members but rather shall be open to all persons and entities with an interest in the reliable operation of the BPS. As noted in the discussion of the first §39.3(b)(1) criterion, above, NERC's Reliability Standards development process is embodied in §300 and Appendix 3A of the ROP. The ROP specify "Essential Principles for the Development of Reliability Standards," which include openness, transparency, consensus-building, fair balance of interest, due process, and timeliness. With respect to balance of interests, the ROP provide for balloting on proposed Reliability Standards to be conducted on the basis of a broad set of ten industry segments, which collectively encompass persons and

entities with an interest in the reliable operation of the BPS. The detailed process steps for developing and approving new or revised Reliability Standards, set forth in the NERC SPM, is based on the procedures of the ANSI and other standards-setting organizations in the U.S. and Canada.

In addition to its rules and procedures for the development of Reliability Standards, NERC's rules provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in the exercise of NERC's other duties, including in the appointment and election of trustees, meetings of trustees, approving amendments to the Bylaws and amendments to the ROP, selection of members for and the conduct of business by committees and subgroups, development and approval of annual business plans and budgets, and the conduct of compliance monitoring and enforcement activities.

Finally, with respect to the requirements of §39.3(b)(2)(v), NERC continues to engage in substantial efforts to gain and maintain recognition as the ERO in Canada and Mexico. One of NERC's corporate purposes, as set forth in its Certificate of Incorporation, is "to act as the electric reliability organization for the United States as certified by the Federal Energy Regulatory Commission and for Canada and Mexico as recognized by applicable government and regulatory authorities in Canada and Mexico, all pursuant to law." In Canada, where by its Constitution the regulation of electricity is primarily within the jurisdiction of each province rather than the national government, NERC's activities to obtain and maintain recognition are conducted on a province-by-province basis. **Attachment 1** details NERC's efforts and accomplishments in the provinces of Alberta, British Columbia, Manitoba, New Brunswick, Nova Scotia, Ontario, Québec, and Saskatchewan, as well as at the National Energy Board. Depending on the particular circumstances of each province, NERC has gained recognition

through statutes or other provisions of provincial law, or through a memorandum of understanding with appropriate entities in the province. As described in **Attachment 1**, NERC's efforts in each province fall into three areas: recognition of NERC Reliability Standards; provisions for sharing of information on issues related to compliance with NERC Reliability Standards; and monitoring and enforcement of compliance with Reliability Standards.

With respect to Mexico, the Comisión Federal de Electricidad (CFE), through the Centro Nacional de Control de Energia (CENACE), and the Area de Control Baja California (ACBC), have entered into a membership and operating agreement (MOA) with WECC. The MOA provides for WECC to assist CENACE and ACBC in monitoring compliance by Designated Entities (the Mexican equivalent of U.S. registered entities) with Mexico Reliability Standards for Baja California, Mexico. CENACE has approved ten Mexico Reliability Standards. Pursuant to the MOA, WECC monitors compliance with Mexico Reliability Standards, but does not have enforcement or registration (designation) authority for CFE. WECC provides compliance monitoring, reviews proposed and completed mitigation plans, and provides assessment recommendations with respect to alleged violations.

In summary, and as shown in detail in **Attachment 1** to this *Five-Year ERO Performance Assessment Report*, the Commission should find that NERC continues to satisfy the requirements of 18 C.F.R. §39.3(b).

IV. REGIONAL ENTITY PERFORMANCE AND EFFECTIVENESS CONTINUES TO IMPROVE

Attachment 3 provides NERC's evaluation of the performance of the Regional Entities in carrying out their delegated authorities and responsibilities during the assessment period.

The Commission's regulation specifying the required contents of the ERO's periodic performance assessment reports states that the performance assessment must include, among

other subjects, the ERO's evaluation of the effectiveness of each Regional Entity and recommendations by the ERO for improvement of the Regional Entity's performance of delegated functions.[91] In its September 16, 2010 Order on NERC's *Three-Year ERO Performance Assessment Report*, the Commission stated that future assessments should include, among other things, separate sections addressing each Regional Entity's satisfaction of statutory and regulatory criteria.[92]

In this five-year performance assessment, NERC organized its evaluation of the Regional Entities' performance based on their principal delegated authorities and responsibilities under the RDAs and the NERC ROP. These segments also correspond to the programmatic organization structures generally followed by NERC and the Regional Entities:

- Regional Reliability Standards Development (**Attachment 3**, §I)
- Compliance Monitoring and Enforcement (**Attachment 3**, §II)
  - Organization Registration and Certification (**Attachment 3**, §II.A)
  - Compliance Monitoring[93] (**Attachment 3**, §II.B)
  - Compliance Investigations (**Attachment 3**, §II.C)
  - Compliance Enforcement (**Attachment 3**, §II.D)
- Reliability Assessments (**Attachment 3**, §III)
- Reliability Risk Management (Situation Awareness and Event Analysis) (**Attachment 3**, §IV)
- Business Planning and Budgeting, Finance and Accounting (**Attachment 3**, §V).

[91] 18 C.F.R. §39.3(c)(1)(iii).

[92] *North American Electric Reliability Corporation, Order on the Electric Reliability Organization's Three-Year Performance Assessment*, 132 FERC ¶ 61,217 (2010), at P 36.

[93] The evaluation of the Regional Entities' performance in Compliance Monitoring includes evaluation of their efforts in providing training, education, and outreach to registered entities and other industry stakeholders on compliance-related matters.

To evaluate the Regional Entities' performance during the assessment period, NERC believed it to be important to use assessment criteria that were well-known to the Regional Entities and that were established at the beginning of, or early in, the assessment period. Accordingly, NERC has generally used the Regional Entities' obligations and responsibilities under the RDAs and the NERC ROP as the basis for evaluating the Regional Entities' performance or as the source for more specific assessment criteria. Although, during the assessment period, the RDAs were significantly revised through a collaborative process among NERC and the Regional Entities, with the revised RDAs going into effect on January 1, 2011 (i.e., approximately 18 months into the assessment period), the Regional Entities' fundamental delegated authorities and responsibilities under the RDAs were not changed in the revised RDAs.

Further, in evaluating the Regional Entities' performance during the assessment period, NERC placed greater emphasis on each Regional Entity's performance during the latter half of the assessment period rather than earlier in the assessment period. Although the assessment is intended to cover the entire five-year period, NERC views the success of a Regional Entity in improving its programs over the course of the period – particularly where improvements have been implemented in response to specific comments, criticisms or recommendations from NERC, the Commission, or the Regional Entity's stakeholders – as especially important to the evaluation. The quality of a Regional Entity's programs and performance as of the end of the assessment period is much more important to the objectives of this review than is a historical review of the Regional Entity's programs and performance at the start of, or in the early portion of, the assessment period. Further, a Regional Entity's willingness to cooperate in implementing new ERO Enterprise initiatives and improvements intended to improve the reliability of the BPS and increase consistency and efficiency across the ERO Enterprise is particularly important to

the evaluation. This focus on improvements, responses to comments and recommendations, and the state of the Regional Entities' programs and performance as of the end of the assessment period, is consistent with the emphasis in the Commission's applicable regulation on comments and recommendations from stakeholders for improvements and the Regional Entity's responses to such comments and recommendations.

In this evaluation of the Regional Entities' performance in the various program areas, NERC has also provided a significant amount of description of NERC's oversight activities of the Regional Entities. NERC's oversight of the Regional Entities' programs and activities provides important context for the performance assessment because, for almost all of the Regional Entities' delegated authorities and responsibilities, NERC's oversight is frequent, and in some areas, virtually continuous. NERC's oversight activities are a significant component of the informational and observational basis for NERC's evaluation of the Regional Entities' performance. Moreover, although this *Five-Year ERO Performance Assessment Report* is appropriately required by the Commission's regulations, it is NERC's ongoing oversight of the Regional Entities' activities that gives NERC both an up-to-date basis for evaluation, and a continuous platform to evaluate the need for and make recommendations for improvements, both in the performance of discrete tasks by individual Regional Entities and on a programmatic, ERO Enterprise-wide basis.

V. NERC HAS SURVEYED STAKEHOLDERS FOR COMMENTS AND SUGGESTIONS FOR IMPROVEMENTS

One of the components of the ERO's periodic assessment reports as specified in 18 C.F.R. §39.3(c) is that the assessment include "[r]ecommendations by Regional Entities, users, owners, and operators of the Bulk-Power System, and other interested parties for improvement of the ERO's operations, activities, oversight and procedures, and the ERO's response to such

recommendations."[94] NERC has addressed this component by soliciting comments and recommendations through (i) a stakeholder survey conducted for purposes of the five-year ERO performance assessment, and (ii) posting drafts of the five-year performance assessment report for stakeholder comment.

The stakeholder survey was initiated on October 31, 2013, near the end of the five-year assessment period, when NERC distributed an online survey seeking stakeholder responses. The survey contained 36 specific questions on topics relating to (i) Reliability Standards development; (ii) compliance monitoring; (iii) compliance enforcement; (iv) organization registration and certification; (v) reliability assessment; (vi) performance analysis and metrics; (vii) training, education and personnel certification; (viii) event analysis; (ix) critical infrastructure protection; (x) shareholder communications, public relations and information technology; (xi) business plan and budget; and (xii) independence and stakeholder input. Stakeholders were invited to respond to the questions using a numerical scoring system and, more importantly, to provide free-form narrative comments on the topics covered by the survey. A total of 326 registered entity responses were received. The respondents were located in all Regional Entities, ranging from a low of 23 responses to a high of 97 responses from respondents located within particular Regional Entities. **Attachment 4** provides the text of the questions that were asked in the survey and also provides summary data on the numbers and distribution of respondents.

With respect to posting drafts of the five-year performance assessment for stakeholder comment, on March 3, 2014, NERC posted a draft statement of its activities and accomplishments during the five-year assessment period, as well as drafts of the Regional

[94] 18 C.F.R. §39.3(c)(1)(ii).

Entities' self-assessments, on the NERC website for stakeholder comment. Subsequently, on June 17, 2014, NERC posted a draft of the *Five-Year ERO Performance Assessment Report* and attachments on its website for stakeholder comment.[95]

Attachment 4 to this *Five-Year ERO Performance Assessment Report* provides the content specified by 18 C.F.R. §39.3(c)(1)(ii). As noted above, **Attachment 4** provides the questions included in the stakeholder survey, reports the average scores from the responses, and provides summary information on the number and distribution of respondents.[96] More importantly, **Attachment 4** provides the significant narrative comments and recommendations submitted by stakeholders and NERC's responses to those comments. To focus on the key issues, questions and recommendations posed or raised by commenters, and for simplicity, NERC has attempted to summarize the comments and to combine them where appropriate, in order to report the gist of the comments and recommendations. The comments are organized in **Attachment 4** in table format by subject matter area: Reliability Standards; Compliance Operations; Enforcement; Registration and Certification; Reliability Assessment & Performance Analysis Metrics; Training, Education and Personnel Certification; Event Analysis; Critical Infrastructure Protection; Stakeholder Communications, Public Relations and IT; and Business Plan and Budget. A separate table, organized into the same topical sections, provides a summary of key stakeholder comments of the Regional Entities. For each stakeholder comment reported in one of the two tables, NERC has provided in the table, opposite the comment, (i) where applicable, the section or sections of the *Overview of NERC Activities and Accomplishments in*

[95] The June 17, 2014 posted draft of **Attachment 4** was incomplete, since completion of that attachment required receipt of the stakeholder comments in response to the posting of the draft report and the preparation of responses to the comments for inclusion in the attachment.

[96] Some of the questions by their nature, pertained only to NERC, while others of the questions pertained to both NERC and the Regional Entities. Average scores are reported for NERC or for NERC and the individual Regional Entities as applicable to the particular survey questions.

the Five-Year Period or of an attachment to this report in which the subject matter of the comment is addressed, and (ii) for most of the comments, a brief narrative response to the comment as well. NERC submits that the tables provided in **Attachment 4** show that NERC has responded to and addressed, or is in the process of responding to and addressing, the key stakeholder comments and recommendations provided in connection with the development of this *Five-Year ERO Performance Assessment Report*.

VI. NERC HAS MADE SUBSTANTIAL PROGRESS IN COMPLETING ACTIONS ON ITEMS IN THE COMMISSION'S ORDER ON THE *THREE-YEAR ERO PERFORMANCE ASSESSMENT REPORT*

NERC's *Three-Year ERO Performance Assessment Report*, filed on July 20, 2009, identified and listed a number of actions to be taken in response to comments received from stakeholders as part of the three-year assessment process.[97] Additionally, the Commission's Order on the three-year ERO performance assessment, issued on September 16, 2010, identified a number of areas for improvement.[98] NERC was directed to submit an informational report to the Commission within six months addressing the directives, concerns and requests for information and/or feasibility reports discussed in the Order. NERC filed the Informational Report on March 16, 2011.[99] NERC was able to report either completion or significant progress with respect to many of the items listed in the Commission's Order.

As part of this *Five-Year ERO Performance Assessment Report*, NERC is providing a further report on its progress in addressing the directives, concerns and requests for information

[97] These actions were listed in Appendix A to **Attachment 1** of the *Three-Year ERO Performance Assessment Report*.

[98] *Order on the Electric Reliability Organization's Three-Year Performance Assessment*, 132 FERC ¶ 61,217 (2010). Appendix A to that Order provided an "Index of Directives" in the Order.

[99] *Informational Filing of the North American Electric Reliability Corporation in Response to the Federal Energy Regulatory Commission's September 16, 2010 Order*, filed March 16, 2011 in Docket Nos. RR09-7-000 and AD10-14-000.

and/or feasibility reports discussed in the Commission's Order on the three-year ERO performance assessment that were not discussed in the March 2011 informational filing. This information is provided in a chart format in **Attachment 5** to this report. As noted in the chart provided as **Attachment 5**, NERC's actions in connection with a number of the items are also discussed in the body of this five-year assessment report.

VII. NERC HAS A VISION AND PLAN FOR IMPROVING COORDINATED OPERATIONS ACROSS THE ERO ENTERPRISE TO REACH THE END STATE OF A HIGHLY EFFECTIVE AND EFFICIENT ERO ENTERPRISE

As described above and in the Attachments to this report, since being certified as the ERO in 2006 and, in particular, during this five-year assessment period, NERC has made substantial progress and recorded significant accomplishments in structuring the ERO Enterprise organization and improving the reliability of the BPS. Despite the achievements to date, the nine-entity structure of the ERO Enterprise, NERC and the eight Regional Entities, is not without certain challenges and risks. Going forward, NERC needs and intends to focus attention on the actions necessary to reach an end-state of a fully-integrated ERO Enterprise that can exercise effective and well-coordinated reliability oversight that mitigates reliability risks to the BPS. Achieving the end-state of a fully integrated ERO Enterprise entails creating greater clarity about the allocation of roles and responsibilities between NERC and the Regional Entities, achieving improved coordination of goals, and establishing more uniform work processes, tools and performance across the ERO Enterprise.

NERC has a vision and plan for achieving this end state of a fully integrated, highly effective and efficient ERO Enterprise. This vision and plan are described in detail in **Attachment 6** to this report.

Reaching this end state necessitates adherence to certain fundamental principles. The ERO Enterprise must:

- Apply technical expertise that is focused on risks to the BPS and important reliability outcomes;
- Achieve results and methods across the ERO Enterprise that are predictable, consistent and timely;
- Share common goals, objectives and measures of success;
- Build relationships that are founded on candor and mutual trust, openness and cooperation;
- Apply collaborative decision-making;
- Ensure efficiencies while minimizing duplication and any activities not affecting reliability outcomes; and
- Avoid undue burden, discrimination, or capriciousness for affected regulated entities.

As detailed in **Attachment 6**, NERC's plan for achieving excellence in the oversight and execution of its statutory functions and in the mitigation of BPS reliability risks requires actions in five areas relating to the relationships and allocations of responsibilities between and among NERC and the Regional Entities:

(1) Clarifying roles and responsibilities. A clear understanding of the roles and responsibilities of NERC and the Regional Entities is required, as well as a clear set of expectations in the execution of the activities performed across the ERO Enterprise. This in turn will necessitate ERO Enterprise program oversight that includes the following essential oversight elements to be provided by NERC in consultation with the Regional Entities:

- An overall program design indicating the program purpose and goals, and design of controls to manage risks;
- Documentation of common methods, practices and procedures to be applied in the program, and performance expectations for each;
- Statements of necessary qualifications of key positions within the Regional Entities for conducting certain statutory activities, and identification of any standards for critical positions;

- Training of NERC and Regional Entity staff for select positions in the conduct of delegated functions;

- A documented and transparent set of process controls and measures to assure delegated responsibilities are properly completed, and to assess the effectiveness of the delegated activities in managing BPS and ERO Enterprise risk; and

- Periodic reporting of results and feedback to Regional Entities on trends and providing opportunities to enhance consistency and effectiveness of results.

To improve the delegation process, it will be important that NERC and the Regional Entities work together to update and refine the RDAs, due for renewal as of January 1, 2016, to provide a clearer division of responsibilities, both related to the division of performance of statutory functions and oversight of those functions, and to provide effective mechanisms to resolve routine differences.

(2) Coordinating strategic planning. NERC and the Regional Entities have collaboratively made significant progress in developing a shared, rolling three-year strategic plan for the ERO Enterprise. However, adoption of the ERO Enterprise goals and objectives into business plans at all of the Regional Entities has varied. In May 2014, the NERC Board approved the 2014 performance metrics. These performance metrics will be used to assess the overall effectiveness of the ERO Enterprise in addressing risk to the BPS, achieving reliability results, assuring Reliability Standards and compliance effectiveness and improving risk mitigation and program execution. They include four overarching metrics focused on overall effectiveness in addressing BPS risks and improving reliability. They also include a number of supporting measures that assess the effectiveness of the key operational elements of the ERO Enterprise. The intent is to report the results of these metrics on an ERO Enterprise-wide basis, and also as applicable, distinguish results for NERC and individual Regional Entities.[100]

[100] *See* http://www.nerc.com/gov/Annual%20Reports/ERO%20Enterprise%20Strategic%20Plan%202014-2017%20and%20Performance%20Metrics.pdf.

(3) Coordinating operational decision-making. The ERO Enterprise model depends on successful delegation of activities, but also requires coordination of operational decisions that arise in the execution of these activities. To date, coordination of policy and directional decisions has been achieved through: (i) coordination meetings between NERC and Regional Entity CEOs, which have become more routinized in recent years and include an agreed-upon protocol for reaching consensus decisions; and (ii) the activities of approximately two dozen working groups collaborating across various functional areas of the ERO Enterprise. The preferred approach going forward is to proactively establish a more collaborative model and recognize that Regional Entity staffs for most functions typically have valuable first-hand experience in implementing the activities on the front lines with registered entities. However, success depends on collaboration that results in timely and effective decisions that all entities in the enterprise agree to implement, and the avoidance of unilateral decision-making that steers portions of the ERO Enterprise into alternative methods and practices for delegated functions.

(4) Achieving consistency. Achieving consistency of methods, practices, procedures and tools has been a challenge throughout the history of the ERO Enterprise. At the outset, given a lack of common processes and procedures from NERC, Regional Entities developed their own methods, practices, procedures and tools. While there has been significant progress made, through the leadership and working groups referred to in the preceding paragraph, in addressing substantive differences, there remain significant variations in methods, practices, procedures and tools across NERC and the eight Regional Entities. Today, the biggest challenge in addressing consistency is gaining common agreement on processes and procedures with the backdrop of years of institutionalized differences among NERC and the Regional Entities.

The ultimate success of the ERO Enterprise depends on there being one compliance

program, one enforcement program, one event analysis program, and so forth. Registered entities will have greater confidence and trust in the ERO Enterprise if they believe regulatory oversight is not subject to arbitrary variations and possible discrimination from one region to the next. Outcomes will be more predictable and consistent if each statutory function is conducted in a unified fashion across the ERO Enterprise. Outcomes will also be more readily measurable to demonstrate the reliability impacts and benefits of the ERO Enterprise programs. In the long term, after the transition from legacy approaches, there will be significant efficiencies.

This transition requires the development of a core set of common methods, practices, procedures, and tools, which NERC is principally responsible to produce, working in collaboration with the Regional Entities. Consistency does not necessarily require identical internal procedures at each Regional Entity, and some flexibility must be maintained to allow for progress through innovation. However, consistency does mean that the approach, methods and practices are the same across the ERO Enterprise and that outcomes produced from application of the local and regional expertise and judgment of the Regional Entity staffs are fair, reasonable and without bias. In other words, the goal is consistent methods, practices, procedures and tools that deliver fair and reasonable outcomes. The move to greater consistency must occur under the close scrutiny of the ERO Executive Management Group, with accountability for progress to the NERC and Regional Entity boards, and all entities must be prepared to adopt changes to drive to more consistent methods, practices, procedures and tools.

(5) Coordinating external and cross-ERO Enterprise communications. Communications are important to the effectiveness of the ERO Enterprise. Communications can help set expectations for registered entities and stakeholders and demonstrate a common and consistent approach for regulators and the public. To facilitate effective communications across the ERO

Enterprise, in May 2013 the NERC Board initiated a practice of meeting twice yearly as a group with all the chairs and vice-chairs of the Regional Entities, with a portion of these meetings conducted with the NERC and Regional Entity CEOs also present. Additionally, a NERC-Regional Entity communications working group has been active for several years, coordinating consistent messaging across the ERO Enterprise. Further, NERC and the Regional Entities have coordinated outreach to FERC Commissioners and staff and to Canadian governments. However, although efforts to coordinate key messages and direction have been successful, areas for improvement remain. Thus, going forward, this area requires further attention to arrive at a desired end-state for the ERO Enterprise.

To reach the desired end-state for the ERO Enterprise in the five areas described above, NERC intends to focus on the following eleven action items:

(1) NERC includes in its review of Regional Entity business plans adequacy of resources and alignment of the plans for achieving delegated function objectives and outcomes described in the three-year plan.

(2) NERC, in collaboration with the Regional Entities:

(a) Develops a comprehensive overarching design and set of controls, reporting requirements, and feedback mechanisms for each delegated statutory function, including the essential oversight elements listed above;

(b) Re-evaluates its organizational structure and leadership qualifications necessary to provide effective design and oversight of statutory activities;

(c) Identifies functional qualifications for select delegated activities, such as auditors and investigators;

(d) Adopts risk-based approaches to monitoring performance of delegated functions and providing effective feedback and coaching to continuously improve overall ERO Enterprise performance; and

(e) Re-evaluates the ERO working group structure to enhance effectiveness.

(3) Regional Entities:

(a) Work in a coordinated fashion to support NERC in the development of comprehensive functional program designs and controls;

(b) Adapt existing regional programs for delegated functions to conform with emerging program designs provided by NERC; and

(c) Ensure Regional Entity staffs meet qualification and training requirements.

(4) NERC and the Regional Entities develop and maintain a joint three-year strategic plan for the ERO Enterprise describing the goals and deliverables for statutory functions and this plan should guide the development of each Regional Entity's annual business plans. Additional goals and deliverables that are complimentary or supplemental to the strategic plan may be developed at the Regional Entity level.

(5) NERC and the Regional Entities transparently report results, based on a common set of performance measures focused on BPS reliability outcomes and effectiveness of the statutory programs. These measures are considered in the performance management program at each entity.

(6) ERO Enterprise senior leadership continues maturing the collaborative decision-making process and setting the direction and policy for the enterprise as well as driving this collaboration throughout the ERO Enterprise organizations.

(7) All nine ERO entities abide by the joint enterprise decisions of the ERO Enterprise senior leadership, and the NERC CEO should make final determinations if consensus is not otherwise achievable for an action that is required.

(8) With NERC leading, the ERO Enterprise develops a core set of methods, practices, procedures, and tools to support unified implementation of the major statutory functions of NERC. In doing so, the ERO Enterprise commits to put the best talent available throughout the collective organizations to achieve this goal.

(9) The ERO Enterprise senior leadership develops ERO Enterprise Information Technology applications, where appropriate, to support common processes, to enhance the efficiency and effectiveness of Regional Entities' practices, to increase the consistency of the interface with registered entities, and to facilitate NERC's oversight function.

(10) All parties of the ERO Enterprise, including leadership and staffs, convey shared and consistent messages from the enterprise perspective and communicate together to minimize messages emphasizing self-importance or uniqueness.

(11) NERC and Regional Entities continue the joint board coordination to ensure oversight and accountability of all elements of the enterprise and should continue to refine and expand coordinated outreach to government entities in the U.S. and Canada, stakeholders, and media.

VIII. CONCLUSION

As detailed in this *Five-Year ERO Performance Report* and its Attachments, NERC has reached an important level of development in identifying, understanding and addressing reliability risks to the BPS. NERC has implemented targeted initiatives that benefit the electric industry and its customers through improved BPS reliability. These initiatives also allow NERC to measure and be accountable for the effectiveness and value of the investments made by the industry to enhance and maintain reliability. NERC's approach allows it to target results around specific issues that benefit the industry and its customers through improved BPS reliability. Further, NERC's programs are continuing to evolve, thereby sharpening its focus on reliability and accountability through risk-based processes.

FEDERAL ENERGY REGULATORY COMMISSION
DOCKET NO. RR14-___

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

ATTACHMENT 1

TO

FIVE-YEAR ELECTRIC RELIABILITY ORGANIZATION PERFORMANCE ASSESSMENT REPORT

DISCUSSION OF HOW NERC MEETS THE ERO CERTIFICATION CRITERIA OF 18 C.F.R. §39.3(b)

JULY 21, 2014

Attachment 1

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I. DISCUSSION OF HOW NERC MEETS THE ERO CERTIFICATION CRITERIA OF 18 C.F.R. §39.3(b)

A. Criterion 1 - The ERO has the ability to develop and enforce, pursuant to 18 C.F.R. §39.7, Reliability Standards that provide for an adequate level of reliability of the BPS.

This criterion encompasses two distinct functions of the ERO: (i) the ability to develop Reliability Standards that provide for an adequate level of reliability of the bulk power system (BPS); and (ii) the ability to enforce those Reliability Standards.

Development of Reliability Standards

NERC develops Reliability Standards pursuant to §300 of its Rules of Procedure (ROP) and its *Standard Processes Manual* (SPM), Appendix 3A to the ROP, both of which have been approved by the Commission as ERO Rules.[1] In addition to having been approved by the Commission, the SPM has been accredited by the American National Standards Institute (ANSI) as meeting ANSI's essential requirements for standards development.

The overall purpose of NERC's Reliability Standards development process, as stated in §301 of the NERC ROP, is to develop and maintain Reliability Standards that apply to BPS owners, operators, and users and that enable NERC and the Regional Entities to measure the reliability performance of the owners, operators, and users and to hold them accountable for the reliable operation of the BPS. Section 301 of the ROP requires that Reliability Standards developed by NERC must be technically excellent, timely, just, reasonable, not unduly discriminatory or preferential, in the public interest, and consistent with other applicable standards of governmental authorities.[2]

In Order No. 672 and the *ERO Certification Order*, the Commission stated that the ERO's Reliability Standards development process must ensure that each Reliability Standard is technically sound; that its operational specifications are designed to achieve a valuable reliability goal; that the standard is clear and unambiguous regarding what is required and who is required to comply; and that there be clear criteria to measure whether an entity is in compliance with the Reliability Standard, so that enforcement can be applied in a consistent and non-preferential manner.[3] Consistent with these requirements, §302 of the ROP specifies the essential attributes of

[1] Sections 304 and 308.1 of the ROP specify that "NERC shall develop Reliability Standards in accordance with the NERC *Standard Processes Manual*, which is incorporated into these Rules of Procedure as Appendix 3A." The current version of the SPM is version 3 which became effective June 26, 2013.

[2] Section 304 of the ROP sets forth NERC's "Essential Principles for the Development of Reliability Standards." These principles, which include openness, transparency, consensus-building, fair balance of interests, due process and timeliness, are discussed under criterion 5, below.

[3] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204 (2006), at PP 258, 262, 325, 327; *Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062 (*ERO Certification Order*), at PP 239, 241.

technically excellent Reliability Standards to be developed by NERC.[4] These essential attributes include:[5]

1. **Applicability** — Each Reliability Standard shall clearly identify the functional classes of entities responsible for complying with the Reliability Standards, with any specific additions or exceptions noted.[6]

2. **Reliability Objectives** — Each Reliability Standard must have a clear statement of purpose that describes how the Reliability Standard contributes to the reliability of the BPS. Section 302.2 of the ROP lists the general objectives for the BPS that provide a foundation for determining the specific objective(s) of each Reliability Standard:[7]

    2.1. **Reliability Planning and Operating Performance** — Bulk Power Systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.

    2.2. **Frequency and Voltage Performance** — The frequency and voltage of Bulk Power Systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

    2.3. **Reliability Information** — Information necessary for the planning and operation of reliable Bulk Power Systems shall be made available to those entities responsible for planning and operating Bulk Power Systems.

    2.4. **Emergency Preparation** — Plans for emergency operation and system restoration of Bulk Power Systems shall be developed, coordinated, maintained, and implemented.

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[4] In the *ERO Certification Order*, the Commission recognized that NERC's proposed ROP provided that the characteristics for technical excellence of a Reliability Standard must be met for a proposed Reliability Standard to be approved. *ERO Certification Order* at P 235.

[5] The descriptions of the essential attributes that follow are summaries, not direct quotes from §302.

[6] The functional classes of entities, or reliability functions, have been developed through NERC's functional model of the BPS, and are defined in its: (i) *Glossary of Terms Used in NERC Reliability Standards*, and (ii) *Statement of Compliance Registry Criteria* which is incorporated into the ROP as Appendix 5B. Currently, the functional classes of entities are: Balancing Authorities (BAs), Distribution Providers, Generator Operators (GOPs), Generator Owners (GOs), Interchange Authorities, Load-Serving Entities, Planning Authorities, Purchasing-Selling Entities, Reliability Coordinators (RCs), Resource Planners, Reserve Sharing Groups, Transmission Operators (TOPs), Transmission Owners (TOs), Transmission Planners, and Transmission Service Providers.

[7] In the *ERO Certification Order*, the Commission recognized that NERC's proposed rules provided that the purpose of a Reliability Standard, or its reliability objective, should derive from one or more of these eight general objectives. *ERO Certification Order* at P 236.

2.5. **Communications and Control** — Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of Bulk Power Systems.

2.6. **Personnel** — Personnel responsible for planning and operating Bulk Power Systems shall be trained and qualified, and shall have responsibility and authority to implement actions.

2.7. **Wide-Area View** — The reliability of Bulk Power Systems shall be assessed, monitored, and maintained on a Wide-Area basis.

2.8. **Security** — Bulk Power Systems shall be protected from malicious physical or cyber attacks.

3. **Performance Requirement or Outcome** — Each Reliability Standard shall state one or more performance Requirements, which if achieved by the applicable entities, will provide for a reliable BPS, consistent with good utility practices and the public interest. Each Requirement is not a "lowest common denominator" compromise, but instead shall achieve an objective that is the best approach for BPS reliability, taking account of the costs and benefits of implementing the proposal.

4. **Measurability** — Each performance Requirement shall be stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by the Requirement. Each performance Requirement shall have one or more associated measures used to objectively evaluate compliance with the Requirement. If performance can be practically measured quantitatively, metrics shall be provided to determine satisfactory performance.

5. **Technical Basis in Engineering and Operations** — Each Reliability Standard shall be based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that field.

6. **Completeness** — Reliability Standards shall be complete and self-contained. The Reliability Standards shall not depend on external information to determine the required level of performance.

7. **Consequences for Noncompliance** — In combination with guidelines for penalties and sanctions and other ERO and Regional Entity compliance documents, the consequences of violating a Reliability Standard are clearly presented to the entities responsible for complying with the Reliability Standards.

8. **Clear Language** — Each Reliability Standard shall be stated using clear and unambiguous language. Responsible entities, using reasonable judgment and in keeping with good utility practices, are able to arrive at a consistent interpretation of required performance.

9. **Practicality** — Each Reliability Standard shall establish Requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter.

10. **Consistent Terminology** — To the extent possible, Reliability Standards shall use a set of standard terms and definitions that are approved through the NERC Reliability Standards development process.[8]

In the *ERO Certification Order*, the Commission concluded that by specifying the eight general objectives for which a Reliability Standard must be intended, and by incorporating other requirements for Reliability Standards development into the essential attributes of technically excellent Reliability Standards, NERC's ROP satisfied the requirements of Order No. 672 for the ERO's Reliability Standards development process.[9]

The NERC SPM also specifies the performance elements of a Reliability Standard.[10] The requirement that each Reliability Standard contain these elements applies a systematic discipline in the development and revision of standards, in order to produce standards that are measurable, enforceable, and consistent. The SPM allows for a clear statement of the purpose, requirements, measures, and compliance elements associated with each standard. The performance elements of a Reliability Standard, as specified in the SPM §2.5, are as follows:

- Title: A brief, descriptive phrase identifying the topic of the Reliability Standard.
- Number: A unique identification number assigned in accordance with a published classification system to facilitate tracking and reference to the Reliability Standards.
- Purpose: The reliability outcome achieved through compliance with the Requirements of the Reliability Standard.
- Applicability: Identified which entities are assigned reliability requirements. The specific Functional Entities and Facilities to which the Reliability Standard applies.
- Effective Dates: Identification of the date or pre-conditions determining when each Requirement becomes effective in each jurisdiction.
- Requirement: An explicit statement that identifies the Functional Entity responsible, the action or outcome that must be achieved, any conditions achieving

[8] In furtherance of the essential attribute of "Consistent Terminology," NERC has developed and maintains the *Glossary of Terms Used in NERC Reliability Standards*, containing definitions of terms that are used in one or more Reliability Standards.

[9] *ERO Certification Order* at PP 239, 241.

[10] SPM at pp. 6-9.

the action or outcome, and the reliability-related benefit of the action or outcome. Each Requirement shall be a statement for which compliance is mandatory.

- Compliance Elements: Elements to aid in the administration of ERO compliance monitoring and enforcement responsibilities.

- Measure: Provides identification of the evidence or types of evidence that may demonstrate compliance with the associated requirement.

- Violation Risk Factors and Violation Severity Levels: Violation risk factors (VRFs) and violation severity levels (VSLs) are used as factors when determining the size of a penalty or sanction associated with the violation of a requirement in an approved Reliability Standard. Each requirement in each Reliability Standard has an associated VRF and a set of VSLs. VRFs and VSLs are developed by the drafting team, working with NERC staff, at the same time as the associated Reliability Standard, but are not part of the Reliability Standard. The Board of Trustees is responsible for approving VRFs and VSLs.

    - Violation Risk Factors: VRFs identify the potential reliability significance of noncompliance with each requirement. Each requirement is assigned a VRF in accordance with the last approved set of VRF criteria.
    - Violation Severity Levels: VSLs define the degree to which compliance with a requirement was not achieved. Each requirement shall have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs. Each requirement is assigned one or more VSLs in accordance with the latest approved set of VSL criteria.

- Version History: The version history is provided for informational purposes and lists information regarding prior versions of Reliability Standards.

- Variance: A Requirement (to be applied in the place of the continent-wide Requirement) that is applicable to a specific geographic area or to a specific set of registered entities.

- Compliance Enforcement Authority: The entity that is responsible for assessing performance or outcomes to determine if an entity is compliant with the associated Reliability Standard. The Compliance Enforcement Authority [(CEA)] will be NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

- Application Guidelines: Guidelines to support the implementation of the associated Reliability Standard.

- Procedures: Procedures to support implementation of the associated Reliability Standard.

The NERC SPM sets forth the detailed process steps for the development and approval of a new Reliability Standard or a revision to an existing standard; the SPM also sets forth the detailed roles of the different persons and groups in in the process.[11] Under the ROP and the SPM, the key groups involved in development of a proposed new Reliability Standard or revision to an existing standard are: (i) the NERC Standards Committee; (ii) the standards authorization request (SAR) drafting team; (iii) the standard drafting team; and (iv) the Registered Ballot Body (RBB).

The Standards Committee is an elected body comprised of two members from each segment of the RBB.[12] The Standards Committee, with the assistance and facilitation of the professional staff of the NERC Reliability Standards development program, oversees the overall standards development process. The Standards Committee ensures that standard development teams have the technical resources and capabilities required to develop technically sound standards that will gain industry support. Among other things, the Standards Committee determines whether SARs submitted by interested persons and entities should be pursued for development, and it appoints members to SAR drafting teams and standard drafting teams.[13] A SAR drafting team is a team of technical experts that, among other responsibilities, assists in refining a SAR and considers and responds to comments.[14] The standard drafting team is a team of technical experts that develops the details of the proposed new or revised Reliability Standard, analyzes results of field tests of the standard (if applicable), and considers and responds to comments.[15] The RBB, which is open to any person or entity and is organized by industry segments, votes on the adoption or rejection of proposed Reliability Standards or revisions to existing standards.[16]

The SPM also specifies roles in the standards development process for the NERC Reliability Standards staff, which is led by the director of standards.[17] Staff provides support to the Standards Committee in managing the Reliability Standards processes and in supporting the work of all drafting teams. More specifically, staff is responsible for ensuring that development

[11] The ROP also provides for an expedited standards development process in the event an applicable governmental authority directs the development of a Reliability Standard within a certain timeframe. This process is described in §309.3 of the ROP.

[12] The segment organization of the RBB is set forth in detail in the *Registered Ballot Body Criteria,* Appendix 3D to the ROP.

[13] *See* SPM at §§3.4 and 3.6.

[14] *See* SPM at §4.2.

[15] SPM at §4.3.

[16] ROP §305; SPM at §§3.2 and 4.7-4.15 (pp. 10, 20-24). Following successful balloting by the ballot pool, a proposed standard is submitted to the NERC Board of Trustees for approval, and if approved by the Board, is filed with the Commission for approval in accordance with §215(d) of the FPA and 18 C.F.R. §39.5. NERC Bylaws, Article IX, §1; ROP §§308.2, 308.3, and 309; and SPM at §§4.0 and 4.16.

[17] SPM at §3.5; *see also* ROP §307.

and revision of standards is in accordance with the SPM, works to ensure the integrity of the Reliability Standards development process and the consistency of quality and completeness of NERC Reliability Standards, and facilitates all steps in the standards development process.

The NERC standards development process relies on the legal and technical expertise provided by the industry experts comprising the SAR drafting teams and standard drafting teams, the technical and administrative assistance provided by the NERC standards process managers and the NERC standards process staff, and the overall oversight and direction of the Standards Committee. Thus, the NERC standards development process ensures that the essential attributes of technically excellent Reliability Standards, including the accomplishment of one of the eight general reliability objectives specified in §§302.2.1 through 302.2.8 of the ROP, are represented in each Reliability Standard that is developed or revised through the process and submitted to the NERC Board of Trustees and, ultimately, to the Commission for approval.

As demonstrated by the table below, NERC has invested significant resources to support its Reliability Standards program. Since 2009, NERC has increased its budgeted resources (direct expenses) for the Reliability Standards program by approximately 143.10% percent from 2009 to 2014:[18]

Year	**Amount**	**Increase over 2009**
2009:	$3,599,454	N/A
2010:	$4,189,050	116.38%
2011:	$4,863,139	135.11%
2012:	$5,307,943	147.47%
2013:	$5,134,738	142.65%
2014:	$5,150,854	143.10%

Leveraging its resources and standards development process, NERC has developed and submitted to the Commission a total of 293 continent-wide Reliability Standards that, as of December 1, 2013, have been approved by the Commission pursuant to §215(d) of the Federal Power Act (FPA) and 18 C.F.R. §39.5 to be mandatory and enforceable. NERC has also approved and submitted to the Commission, and the Commission has approved, a total of 23 regional Reliability Standards as of December 1, 2013. NERC's success to date in developing Reliability Standards that the Commission subsequently approved as mandatory and enforceable

[18] *See December 2008 Budget Compliance Filing* Attachment 1 at 1; *NERC 2010 Business Plan and Budget* at 36 and Attachment 2 at 15; *NERC 2011 Business Plan and Budget* at 35 and Attachment 2 at 27; *NERC 2012 Business Plan and Budget* at 37 and Attachment 2 at 26; *NERC 2013 Business Plan and Budget* at 42 and Attachment 2 at 34; *NERC 2014 Business Plan and Budget* at 43 and Attachment 2 at 29. The amounts cited are direct expenses only and do not include NERC indirect expenses (General and Administrative, Information Technology, Legal and Regulatory, Human Resources, and Finance and Accounting) allocated to the Reliability Standards Program Area.

demonstrates that NERC has, and has exercised, the ability to develop Reliability Standards that provide for an adequate level of reliability of the BPS.

Further, the continent-wide Reliability Standards that have been developed by NERC and approved by the Commission cover the full range of reliability objectives specified in §302 of the NERC ROP:

- Resource and Demand Balancing (25 approved standards)
- Communications (3 approved standards)
- Critical Infrastructure Protection (55 approved standards)
- Emergency Preparedness and Operations (21 approved standards)
- Facilities Design, Connections and Maintenance (21 approved standards)
- Interchange Scheduling and Coordination (18 approved standards)
- Interconnection Reliability Operations and Coordination (29 approved standards)
- Modeling, Data, and Analysis (33 approved standards)
- Nuclear (2 approved standards)
- Personnel Performance, Training and Qualifications (9 approved standards)
- Protection and Control (29 approved standards)
- Transmission Operations (21 approved standards)
- Transmission Planning (15 approved standards)
- Voltage and Reactive Power (12 approved standards)

In accordance with the template and performance elements specified in the SPM, each approved Reliability Standard contains the following clearly-identified sections and subsections: (i) Applicability — stating the title of the standard, its identification number, its purpose, the reliability functional entities to which it is applicable, and its effective date; (ii) Requirements; (iii) Measures; (iv) Compliance — stating the entity responsible for monitoring compliance; the compliance monitoring period and reset timeframe; data retention requirements for the registered entities; and the levels of noncompliance for specified types of violations of the standard; and (v) Regional Differences, if any.

The inclusion of these elements helps to ensure that Reliability Standards clearly state who is responsible for compliance with a Reliability Standard, the Requirements for which compliance is required, and how compliance may be measured by the CEA.

NERC systematically manages the development of new standards and revisions to standards, in areas of highest need and importance, through its rolling three-year *Reliability Standards Development Plan*. The *Reliability Standards Development Plan* identifies and prioritizes the Reliability Standards development projects in the immediate three-year time horizon. The three-year *Reliability Standards Development Plan* is revised annually, based on input from NERC staff, the standard drafting teams, the NERC technical committees and subgroups, other industry participants, and government authorities. The annual *Reliability Standards Development Plan* revision considers: (i) perceived gaps in NERC's Reliability Standards and proposals for closing those gaps; (ii) timing priorities of the projects in the *Reliability Standards Development Plan* and recommendations for adjusting the timing of individual projects; and (iii) potential new projects for development of new standards or revisions to existing standards. The three-year rolling *Reliability Standards Development Plan*, as revised each year, is submitted to the NERC Board of Trustees for approval and then filed with the Commission for information. The *Reliability Standards Development Plan 2014-2016* was approved by the NERC Board of Trustees on November 7, 2013 and continues the approach set forth in the *Reliability Standards Development Plan 2013-2015*; namely, to facilitate the transformation of NERC Reliability Standards to "steady-state," a set of standards that are stable, clear, concise, high-quality, results-based, and technically sound, while emphasizing addressing outstanding regulatory directives and the retirement of Reliability Standards that do little to promote reliability.[19]

Enforcement of Reliability Standards

NERC's program for monitoring and enforcing compliance with Commission-approved Reliability Standards is implemented through its *Compliance Monitoring and Enforcement Program* (CMEP) (§400 and Appendix 4C to the ROP), its Organization Registration and Certification Programs (§500 to the ROP), its *Sanction Guidelines* (Appendix 4B to the ROP), and its delegation agreements with the eight Regional Entities.[20]

Section 6(a) of NERC's delegation agreements with the Regional Entities specifies that the Regional Entity shall enforce Reliability Standards within its geographic boundaries through the compliance enforcement program set forth in Exhibit D to the agreement, and that the Regional Entity's compliance monitoring and enforcement program meets all applicable requirements of the FPA, Commission Order No. 672, and the Commission's regulations, including, *inter alia*, the requirement for an audit program pursuant to 18 C.F.R. §39.7(a), the assessment of penalties pursuant to 18 C.F.R. §39.7(c) through 39.7(g), and the requirements for due process. Additionally, §6(f) of the delegation agreements requires the Regional Entity to maintain the

[19] The *Reliability Standards Development Plan 2014-2016*, along with previous versions of the plan, are available at: http://www.nerc.com/pa/Stand/Pages/ReliabilityStandardsDevelopmentPlan.aspx.

[20] The delegation agreements were originally approved by the Commission in an order issued April 19, 2007 (*Order Accepting ERO Compliance Filing, Accepting ERO/Regional Entity Delegation Agreements, and Accepting Regional Entity 2007 Business Plans*, 119 FERC ¶ 61,060 (2007)), subject to various compliance requirements, which have been addressed in subsequent compliance filings and Commission orders. The currently-effective delegation agreements will expire on December 31, 2015.

capability to conduct investigations of potential violations of Reliability Standards and to conduct such investigations in a confidential manner. It also requires the Regional Entity to maintain a program of proactive enforcement audits, including procedures for spot checks of self-reported compliance and periodic audits of all registered entities.

Through the NERC Organization Registration and Certification Programs, NERC and the Regional Entities have identified users, owners, and operators of the BPS that are obligated to comply with Commission-approved NERC Reliability Standards.[21] Section 500 of the NERC ROP governs the registration of users, owners, and operators of the BPS as responsible for compliance with the requirements of Reliability Standards that are applicable to the reliability function for which the entity is registered. The purpose of the NERC Compliance Registry, established pursuant to §501 of the ROP, is to clearly identify those entities that are responsible for compliance with Reliability Standards. The NERC Compliance Registry identifies the reliability functions to be performed by each organization responsible for meeting the requirements of Reliability Standards. Organizations listed in the NERC Compliance Registry are responsible for knowing the contents of, and complying with, Reliability Standards applicable to the reliability function(s) for which the entity is registered.[22] The criteria upon which users, owners and operators of the BPS will be registered for one or more reliability functions are specified in §501 of the ROP and in NERC's FERC-approved *Statement of Compliance Registry Criteria* (Appendix 5B to the ROP). The purpose of the *Organization Registration and Certification Manual* (Appendix 5A) is twofold: (i) to define the process utilized in the Organization Registration Program by identifying which functional entities must register as owners, operators, and users of the BPS for compliance with Reliability Standards; and (ii) to define the process utilized in the Organization Certification Program for certifying the following entities: RC, BA, and TOP.

Typically, a user, owner or operator of the BPS is identified, in the first instance, for placement on the NERC Compliance Registry by the Regional Entity in whose territory the user, owner or operator is located. Upon the entity being notified by NERC that it is being placed on the NERC Compliance Registry, the entity may challenge its inclusion on the NERC Compliance Registry by filing a written objection with NERC.[23] Challenges to inclusion on the NERC Compliance Registry are heard and decided by the NERC Board of Trustees Compliance Committee (BOTCC). If the entity is not satisfied with the decision of the BOTCC, the entity may appeal the registration determination to the Commission.[24] NERC may remove a registered entity from the NERC Compliance Registry for one or more of the reliability functions for which the

[21] Section 215(b)(2) of the FPA requires all users, owners and operators of the BPS to comply with Reliability Standards approved by the Commission. Similarly, the Commission's regulations at 18 C.F.R. §39.2 and §40.2 require all users, owners, and operators of the BPS to comply with applicable Reliability Standards and applicable rules of the ERO and Regional Entities approved by the Commission.

[22] ROP §501. The current categories of reliability functional entities are listed in ROP Appendix 5B, *Statement of Compliance Registry Criteria*. *See also supra* n. 6.

[23] A user, owner, or operator of the BPS may be listed on the NERC Compliance Registry for several reliability functions. A registered entity may challenge its listing for one or more of the reliability functions for which it has been registered while accepting its listing for other reliability function(s).

[24] The registration, challenge, and appeal process described in this paragraph is set forth in §501.1.3 of the ROP.

entity is listed, based on changed circumstances. As of December 31, 2013, there were 1,920 organizations listed on the NERC Compliance Registry, registered for 4,794 reliability functions.

Monitoring and enforcement of compliance with Reliability Standards is conducted primarily by the eight NERC Regional Entities, pursuant to §401.4 of the NERC ROP and the delegation agreements between NERC and the Regional Entities. Each Regional Entity is responsible for compliance monitoring and enforcement activities within its regional footprint.[25] The ROP provide for NERC to take responsibility for CMEP activities where a Regional Entity is unable to perform those functions, as well as to be responsible for overseeing the CMEP activities of the Regional Entities.[26] Section 403 of the ROP describes in detail the required attributes of Regional Entity compliance programs, covering compliance program structure, compliance program resources, and compliance program design. Section 403 emphasizes the requirement that the Regional Entity's governance of its compliance program, and its compliance program staff, be independent.[27] Each Regional Entity must develop a Regional Entity Compliance Enforcement Implementation Plan that identifies the Reliability Standards to be actively monitored by the Regional Entity (both those required by NERC and any additional Reliability Standards the Regional Entity proposes to monitor), and how the identified Reliability Standards will be monitored, evaluated, reported, sanctioned, and appealed.[28] These plans must be developed on an annual basis and submitted to NERC for approval. In its annual Implementation Plan, each Regional Entity must also report to NERC how the Regional Entity carried out its delegated compliance enforcement authority in the previous year, the effectiveness of its CMEP, and changes expected to correct any identified deficiencies.[29]

NERC is required to conduct an audit, at least once every five years, to evaluate how each Regional Entity implements the NERC CMEP.[30] The evaluation is based on the ROP including the NERC CMEP, the delegation agreement with the Regional Entity, the approved Regional Entity annual CMEP Implementation Plans, the required CMEP attributes, and the CMEP procedures. NERC must provide its evaluations to the Commission and other appropriate ERO

[25] ROP §401.4.

[26] ROP §§401.5, 402, and 404. The Commission has also approved the practice of one Regional Entity entering into an agreement with another Regional Entity to administer the compliance processes in the NERC CMEP with respect to the Regional Entities' registered functions. *See*, e.g., *Order Conditionally Accepting Compliance Monitoring and Enforcement Program Agreements and Revised Delegation Agreements, and Ordering Compliance Filing*, 132 FERC ¶ 61,024 (2010).

[27] ROP §§403.1 and 403.6.

[28] ROP §§402.1.1.1 and 403.16.

[29] ROP §403.16.

[30] ROP §402.1.1.3.

governmental authorities to demonstrate the effectiveness of each Regional Entity in compliance monitoring and enforcement.[31]

NERC has also conducted spot checks of different aspects of the Regional Entities' implementation of the CMEPs in 2013 and 2014. In 2013, NERC conducted a spot check of Regional Entity dismissal procedures. NERC also conducted a spot check of Regional Entity processes and procedures relating to settlement agreements and notices of confirmed violation. In 2014, NERC plans to conduct a spot check of Regional Entity processes regarding mitigation plans. These spot checks are in addition to NERC's ongoing spot check of issues filed pursuant to NERC's Find, Fix, Track and Report (FFT) program.

The controlling document for NERC's compliance monitoring and enforcement activities is the NERC CMEP, Appendix 4C to the ROP. Pursuant to Exhibit D to its delegation agreement with NERC, each Regional Entity has either adopted the NERC CMEP or a modified version of the CMEP; in the latter case, the modified CMEP, or an enumeration of any deviations in the Regional Entity's CMEP from the uniform CMEP, is included in Exhibit D to the Regional Entity's delegation agreement. All CMEPs have been approved by the Commission.[32]

The NERC CMEP (as well as each of the modified Regional Entity CMEPs) provides for seven compliance monitoring methods: (i) audits of registered entities for compliance with Reliability Standards;[33] (ii) self-certifications by registered entities of their compliance with standards;[34] (iii) spot checks of registered entities' compliance with Reliability Standards;[35] (iv) compliance investigations (CIs), which may be conducted and led by the Regional Entity or by NERC;[36] (v) self-reports by registered entities of violations of Reliability Standards;[37] (vi) periodic

[31] ROP §402.1.3. The audit procedure for NERC's audits of the Regional Entity CMEPs is contained in *Audit of Regional Entity Compliance Programs*, Appendix 4A to the ROP.

[32] The Commission initially approved the NERC CMEP and modified CMEPs adopted by certain Regional Entities in their respective delegation agreements, subject to various compliance requirements, in its Order issued April 19, 2007. *Order Accepting ERO Compliance Filing, Accepting ERO/Regional Entity Delegation Agreements, and Accepting Regional Entity 2007 Business Plans*, 119 FERC ¶ 61,060 (2007). Subsequent Commission orders have approved modifications to the NERC CMEP and Regional Entity CMEPs (both modifications in response to Commission directives and modifications initiated by NERC and/or Regional Entities). *See*, e.g., *Order Conditionally Approving Revised Pro Forma Delegation Agreement, Revised Delegation Agreements with Regional Entities, Amendments to Rules of Procedure and Certain Regional Entity Bylaws*, 133 FERC ¶ 61,061 (2010); *Order Conditionally Accepting Compliance Monitoring and Enforcement Program Agreements and Revised Delegation Agreements, and Ordering Compliance Filings*, 132 FERC ¶ 61,024 (2010); *Order Conditionally Approving Revisions to North American Electric Reliability Corporation Rules of Procedure*, 141 FERC ¶ 61,241 (2012).

[33] CMEP §3.1.

[34] CMEP §3.2.

[35] CMEP §3.3.

[36] CMEP §3.4.

[37] CMEP §3.5.

data submittals by registered entities as requested by the CEA;[38] and (vii) investigation of complaints.[39] The NERC CMEP sets forth detailed process steps for each of the seven compliance monitoring methods, including requirements for the results of the processes to be reported by the Regional Entity to NERC and ultimately to the Commission. The NERC CMEP provides for due process for a registered entity by including provisions that address avoidance of conflicts of interest,[40] preservation of confidentiality,[41] provision of notice, and opportunities to respond.[42]

As specified by §4.1 of the NERC CMEP, NERC develops and posts an annual CMEP Implementation Plan each year. The annual NERC CMEP Implementation Plan specifies, among other information, the Reliability Standards to be actively monitored during the upcoming year and the compliance process(es) to be used by the CEAs to monitor each Reliability Standard. The annual NERC CMEP Implementation Plan is used by the Regional Entities in developing their individual annual regional Compliance Enforcement Program Implementation Plans.

The NERC CMEP also specifies the processes to be followed when an alleged violation of a Reliability Standard by a registered entity is identified,[43] including notification to the registered entity of an alleged violation and the required contents of the notice;[44] the registered entity's response to the notification of alleged violation;[45] the opportunity for the registered entity to obtain a hearing on the alleged violation and/or proposed penalty or sanction before the CEA hearing

[38] CMEP §3.6. The CEA is the entity (either NERC or the Regional Entity, as applicable) responsible for monitoring and enforcing the registered entity's compliance with Reliability Standards. CMEP §1.1.7.

[39] CMEP §3.7.

[40] For example, the registered entity is notified in advance of a compliance audit as to the members of the audit team (who are required to be free of conflicts of interest) and their backgrounds and is given the opportunity to object to individual members of the audit team on grounds of a conflict of interest or other circumstance that could interfere with the team member's impartial performance of his or her duties. *See* CMEP §3.1.5. Similar notice and opportunity to object is provided with respect to spot checking teams (*id.* at §3.3.1) and CI teams (*id.* at §3.4.1). In addition, §6 of the NERC-Regional Entity delegation agreements requires the Regional Entity to maintain a conflict of interest policy that assures the integrity of its compliance enforcement program and the independence of the compliance program staff from those subject to enforcement actions.

[41] CMEP §§2.0 and 9.3. In addition, §6 of the NERC-Regional Entity delegation agreements specifies that each violation or alleged violation of a Reliability Standard shall be treated as nonpublic until the matter is filed with the Commission as a notice of penalty or resolved by an admission that the owner, operator, or user of the BPS violated a Reliability Standard or by a settlement or other negotiated disposition.

[42] For example, the CEA must notify the registered entity in advance of a compliance audit as to the Reliability Standards to be covered by the audit, and must provide a pre-audit questionnaire to the registered entity at least two months before commencement of the audit. NERC uniform CMEP §3.1.1. At the conclusion of the audit, the compliance audit team is required to provide a draft audit report to the registered entity for comment. *Id.* §3.1.6. Similarly, in the spot check and periodic data submittal processes, the CEA is required to provide its draft assessment of compliance to the registered entity for comment. *Id.* §3.3.1 and §3.6.1.

[43] CMEP §5.0.

[44] CMEP §§5.1 and 5.3.

[45] CMEP §5.4.

body;[46] the process the registered entity may engage in to negotiate a settlement with the CEA;[47] the registered entity's right to appeal a hearing body decision to NERC;[48] and the process for reporting a penalty or sanction to the Commission for confirmation.[49]

The NERC CMEP requires that a registered entity found to be in violation of a Reliability Standard must file a mitigation plan with the CEA to correct the violation, or a description of how the violation has been mitigated.[50] The NERC CMEP describes the required contents of the registered entity's proposed mitigation plan;[51] the processes for submittal of the proposed mitigation plan by the Regional Entity[52] and for review and acceptance or rejection of the proposed mitigation plan by the Regional Entity and review and approval or disapproval by NERC (and, in the latter event, modification of the mitigation plan by the registered entity);[53] the timetable for completion of an accepted mitigation plan;[54] and the process for completion and confirmation by the CEA of implementation of the registered entity's mitigation plan.[55] Key components required by the NERC CMEP to be in any mitigation plan are the registered entity's action plans to correct the violation(s) and to prevent recurrence.[56]

Additionally, the NERC CMEP provides the procedure for the CEA to issue a remedial action directive to a registered entity.[57] A remedial action directive may be issued, when immediately necessary to protect the reliability of the BPS from an imminent threat, to a registered entity the CEA believes is committing or has committed a violation of a Reliability Standard. The remedial action directive may include, but is not limited to, specifying operating or planning

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[46] CMEP §5.5 and Attachment 2, *Hearing Procedures*. The *Hearing Procedures* set forth the detailed procedures for the hearing to be conducted before the CEA hearing body should a registered entity dispute a notice of alleged violation, proposed penalty or sanction, proposed mitigation plan, or a remedial action directive.

[47] CMEP §5.6.

[48] CMEP §5.7. The NERC appeal process is addressed in §§408 and 409 of the ROP.

[49] CMEP §5.9.

[50] CMEP §6.1.

[51] CMEP §6.2.

[52] CMEP §6.4.

[53] CMEP §6.5.

[54] CMEP §6.3.

[55] CMEP §6.6.

[56] CMEP §6.2.

[57] CMEP §7.0. A remedial action directive is "[a]n action (other than a [p]enalty or sanction) required by a Compliance Enforcement Authority that (1) is to bring a [r]egistered [e]ntity into compliance with a Reliability Standard or to avoid a Reliability Standard violation, and (2) is immediately necessary to protect the reliability of the Bulk Power System from an imminent or actual threat." CMEP §1.1.27.

criteria, limits or limitations; requiring specific system studies; defining operating practices or guidelines; requiring confirmation of data, practices or procedures through inspection, testing or other methods; requiring specific training for personnel; requiring development of specific operating plans; directing a registered entity to develop and comply with a plan to remediate a violation; imposing increased auditing or additional training requirements; and requiring the registered entity to cease an activity that may constitute a violation of a Reliability Standard.[58]

As a key component of the enforcement of compliance with mandatory Reliability Standards, a violation of a standard can result in the imposition of a financial penalty or other penalty or sanction on the registered entity. NERC has established, and is applying, rules and procedures for determining the amount of financial penalties, or other penalties or sanctions, to be imposed on registered entities for violations of Reliability Standards. These rules and procedures are embodied in the NERC *Sanction Guidelines*, Appendix 4B to the ROP. The *Sanction Guidelines* must be followed by the Regional Entities in the implementation of their CMEPs.[59] Penalties and sanctions must bear a reasonable relation to the seriousness of the violation and take into consideration timely remedial efforts by the registered entity.[60] NERC's rules and procedures for determining appropriate penalties and sanctions for violations of Reliability Standards are discussed in greater detail under criterion 4.[61]

In order to carry out their responsibilities to monitor and enforce compliance with Reliability Standards, NERC and the Regional Entities, over the period from 2009 to date, have developed substantial professional staffs for, and are devoting substantial resources to, their CMEP and Organization Registration Programs. The following table shows the direct expenses and the numbers of full-time equivalent (FTE) staff budgeted by NERC and each Regional Entity in 2009 and in 2014.[62]

[58] CMEP §7.0.

[59] ROP §§403.14 and 407.

[60] ROP §401.7.

[61] The ERO has established rules that provide fair and impartial procedures for enforcement of Reliability Standards through the imposition of penalties in accordance with 18 C.F.R. §39.7, including limitations on activities, operations, or other appropriate sanctions or penalties.

[62] *See NERC 2009 Business Plan and Budget; December 2008 Budget Compliance Filing; NERC 2014 Business Plan and Budget.* The amounts cited are direct expenses only and do not include NERC indirect expenses (General and Administrative, Information Technology, Legal and Regulatory, Human Resources, and Finance and Accounting) allocated to the Compliance Monitoring and Enforcement and Organization Registration and Certification Program Area.

Regional Entity	2009 Budgeted FTEs	2009 Budgeted Direct Expense ($)
NERC	35.50	7,358,536
FRCC	9.10	1,991,643
MRO	10.00	2,071,510
NPCC	9.00	2,095,204
ReliabilityFirst	23.00	5,099,328
SERC	21.50	4,805,617
SPP RE	6.00	1,283,653
Texas RE	14.15	1,628,935
WECC	30.00	6,165,303
Totals	**158.25**	**32,499,729**

Regional Entity	2014 Budgeted FTEs	2014 Budgeted Direct Expense ($)
NERC	41.28	7,902,272
FRCC	19.26	4,281,909
MRO	21.26	3,864,192
NPCC	16.00	5,080,485
ReliabilityFirst	43.00	9,788,246
SERC	42.50	7,389,556
SPP RE	22.10	4,258,217
Texas RE	40.00	5,991,654
WECC	58.00	8,592,053
Totals	**303.40**	**57,148,584**

As demonstrated in the tables above, the number of budgeted FTEs increased approximately 191.72% across NERC and the Regional Entities from 2009 to 2014, while the budgeted direct expense increased by nearly 175.84%.

In addition to their compliance program staffs, NERC and a number of the Regional Entities have also made use of consultants and contractors to assist in compliance audits, CIs, and other compliance monitoring and enforcement activities, and to provide subject matter expertise as needed to supplement the expertise of their staffs.

As explained in the *Joint Regional Entity Self-Assessment*, included in **Attachment 2** of this *Five-Year ERO Performance Report*, the Regional Entities describe how they execute their delegated function of enforcing Reliability Standards. Also in **Attachment 2**, the Regional Entities describe their compliance monitoring activities during the 2009 through 2013 assessment period.

NERC has participated in some Regional Entity compliance audits and will continue to do so as an observer to observe the performance of audits by the Regional Entities and to help ensure

consistent implementation and application of the CMEP and consistent application of the requirements of standards across the Regional Entities.

The foregoing discussion amply demonstrates that NERC has developed and is implementing the ability to develop and enforce Reliability Standards that provide for an adequate level of reliability of the BPS.

B. Criterion 2 - The ERO has established rules that assure its independence of users, owners and operators of the BPS while assuring fair stakeholder representation in the selection of its directors and balanced decision-making in any ERO committee or subordinate organizational structure.

This criterion encompasses three distinct considerations: (i) independence of NERC from users, owners and operators of the BPS; (ii) fair stakeholder representation in the selection of NERC's directors (trustees); and (iii) provision for balanced decision-making in any NERC committee or subordinate organizational structure.

Independence of Users, Owners, and Operators of the BPS

NERC's Bylaws provide that NERC's business and affairs shall be managed by a Board of Trustees.[63] The Bylaws provide that the Board of Trustees shall consist of ten independent trustees plus the President of NERC.[64] The Bylaws define "independent trustee" as follows:

> An independent trustee is a person (i) who is not an officer or employee of the Corporation [i.e., NERC], a member or an officer, director, or employee of a member of the Corporation, or an officer, director, or employee of any entity that would reasonably be perceived as having a direct financial interest in the outcome of board decisions and (ii) who does not have any other relationship that would interfere with the exercise of independent judgment in carrying out the responsibilities of a trustee. Provided, that upon initial election to the board, an independent trustee shall within ten (10) days terminate any employee, officer, or director position that conflicts with this subparagraph and shall within sixty (60) days terminate any financial interest or other relationship that conflicts with this subparagraph, and prior to such termination shall not participate in discussion of or voting on any matter involving the entity of which the trustee is an employee, officer or director or in which the trustee has the financial interest or other relationship giving rise to the conflict.[65]

[63] NERC Bylaws Article III, §1.

[64] NERC Bylaws Article III, §1. On October 14, 2009, the Commission approved in a letter order, in Docket No. RR09-8-000, new §§1a and 1b that allows the Board of Trustees to exercise the authority to increase the number of trustees from eleven to twelve, and decrease from twelve to eleven, respectively.

[65] NERC Bylaws Article III, §3a. The last sentence of §3a, providing for brief time periods for a newly-elected trustee to terminate any employment, officer or director position or financial interest or other relationship that would prevent

In the *ERO Certification Order*, the Commission found that the NERC Bylaws definition of "independent trustee" was sufficient to provide for independence from users, owners and operators of the BPS, subject to one clarification.[66]

Thus, a NERC trustee cannot be an officer, director, or employee of a member of NERC nor of any other entity that would be perceived as having a direct financial interest in the outcome of board decisions, and may not have any other relationship that would interfere with the exercise of independent judgment in carrying out the responsibilities of a trustee. The "responsibilities of a trustee" include, among other things, voting on: (i) board approval of proposed Reliability Standards;[67] (ii) board approval of the NERC ROP and amendments to the ROP;[68] and (iii) board approval of NERC and Regional Entity budgets.[69] Committees of the NERC Board, such as the BOTCC, are responsible for decisions such as hearing and deciding challenges by a user, owner or operator of the BPS to placement of the entity on the NERC Compliance Registry,[70] hearing and deciding appeals from a Regional Entity hearing body decision on a registered entity's challenge to a notice of alleged violation of a Reliability Standard and/or proposed penalty or sanction,[71] and approving the imposition of penalties or other sanctions for violations of Reliability Standards on registered entities, including by settlements.

In addition, the NERC *Conflict of Interest and Business Ethics Policy for Trustees, Officers and Employees* specifies that NERC Representatives "shall avoid and refrain from involvement in or situations where there is actually a conflict of interest (Conflict). A Conflict arises where the NERC Representative's personal financial interest is significantly affected or may reasonably appear to be significantly affected by his or her actions or decisions in his or her capacity at

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the trustee from being independent, is a 2008 amendment to the Bylaws that was approved by the Commission by a letter order issued October 7, 2008 in Docket No. RR08-5-000.

[66] *ERO Certification Order*, 116 FERC ¶61,062 at P 42. The clarification is that the definition prohibits an independent trustee from having a relationship that would interfere with his or her exercise of independent judgment in carrying out the responsibilities of a trustee, regardless of whether he or she is an officer, director, or employee of an entity with an interest in the outcome of NERC Board of Trustees decisions. NERC confirmed this clarification in a compliance filing dated September 18, 2006, and made a modification, consistent with the clarification, to the definition of "independent trustee" in its Bylaws. *Compliance Filing of the North American Electric Reliability Council and the North American Electric Reliability Corporation Addressing Governance Issues and Request for Expedited Treatment*, Docket No. RR06-1, filed September 18, 2006 (*NERC ERO Governance Compliance Filing*) at 3-4.

[67] NERC Bylaws Article IX, §1; ROP §308.2.

[68] NERC Bylaws Article XI, §2; ROP §1402.

[69] NERC Bylaws Article XIII, §§2, 3, 4, and 5; ROP §1101. Each of the matters just listed, upon being approved by the NERC Board of Trustees, must then be submitted to the Commission for approval or confirmation. Sections 215(d) and (f) of the FPA and 18 C.F.R. §§39.4(b), (c), and (d), and 39.5.

[70] ROP §501.1.3.

[71] ROP §409.

NERC." NERC's *Process for Reviewing Conflicts of Interes*t outlines how potential conflicts of interest of the independent trustees, officers and employees are evaluated beginning in December of each calendar year.[72] The *NERC Employee Code of Conduct* mandates an "employee's faithful pursuit of the interests of NERC rather than his or her own financial or other interests of another person or organization." Finally, NERC's *Policy on Reporting Complaints Regarding Accounting and Code of Conduct Matters* prohibits retaliation against any NERC employee who lodges a code of conduct complaint about fraud, unethical business conduct, questionable accounting, problems with internal accounting controls, financial reporting or auditing, violations of NERC's codes of conduct for trustees and employees, or violations of law occurring within NERC.

Fair Stakeholder Representation in the Selection of NERC's Trustees

NERC's Bylaws provide for fair stakeholder representation in the selection of NERC's trustees. Candidates for election as a trustee are selected by a nominating committee. The nominating committee is appointed annually (or more frequently if needed in the event of a special election to fill a board vacancy) by the board. The nominating committee is to consist of those independent trustees whose terms do not expire during the current year and such number of other persons with such qualifications as the board shall specify, including at least three members of the NERC Member Representatives Committee (MRC).[73] The procedures to be followed by the nominating committee must include a means of permitting members of NERC to recommend to the nominating committee candidates for consideration as nominees for independent trustees.[74] NERC's Bylaws specify that the nominating committee "shall also endeavor to nominate candidates for election to the board consistent with the objectives that the board as an entity reflects expertise in the areas of technical electric operations and reliability, legal, market, financial, and regulatory matters, and familiarity with regional system operations issues; and reflects geographic diversity."[75]

NERC's Bylaws provide that the independent trustees shall be elected by the NERC MRC, from nominees proposed by the nominating committee. To be elected an independent trustee, a nominee must receive the affirmative vote of two-thirds of the members of the MRC.[76] The MRC

[72] On February 6, 2014, the NERC Board of Trustees approved *Governance Guidelines*, which consolidated NERC's (i) *Conflict of Interest and Business Ethics Policy for Trustees, Officers and Employees* and (ii) *Process for Reviewing Conflicts of Interest* into a single cohesive document.

[73] NERC Bylaws Article III, §5.

[74] NERC Bylaws Article III, §5.

[75] NERC Bylaws Article III, §5.

[76] NERC Bylaws Article III, §6. The NERC Bylaws also require that the number of trustees from Canada shall not be less than the percentage of the net energy for load (NEL) of Canada to the total NEL of the United States and Canada, times eleven (or twelve if the number of trustees has been increased to twelve pursuant to NERC Bylaws Article III, §1a), rounded up to the nearest whole number, with the management trustee (i.e., the president of NERC) counted as a trustee from Canada if he or she is a Canadian citizen. NERC Bylaws Article III, §2a. In the *ERO Certification Order*, the Commission approved this provision as "adequately provid[ing] for an international ERO," stating that "appropriate country representation helps to ensure that the ERO is truly international in addressing Bulk-

is comprised of representatives from the various sectors of the NERC membership.[77] As specified by Article II, §4 of the NERC Bylaws, the sectors of the NERC membership are: (i) investor-owned utilities; (ii) state/municipal utilities; (iii) cooperative utilities; (iv) federal or provincial utilities/federal power marketing administrations; (v) transmission-dependent utilities; (vi) merchant electricity generators; (vii) electricity marketers; (viii) large end-use electricity customers; (ix) small end-use electricity customers; (x) independent system operators/regional transmission organizations; (xi) regional entities; and (xii) government representatives.[78] The composition of the MRC, as specified in Article VIII, §2 of the NERC Bylaws, is as follows:

(1) Two representatives from each sector except the government representative sector and the regional entity sector;

(2) Two voting representatives from the regional entity sector, with the remaining members of that sector being non-voting members of the MRC;[79]

(3) The chairman and vice chairman of the MRC;[80]

(4) Any additional Canadian representatives as are selected pursuant to Article VIII, §4 of the Bylaws;[81] and

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Power System reliability and considering the concerns of stakeholders in each of the three countries." *ERO Certification Order* at P 47.

[77] Membership in NERC is voluntary and is open to any person or entity that has an interest in the reliable operation of the North American BPS, registers as a member, and complies with the other conditions and obligations of membership specified in the NERC Bylaws (which do not include payment of any membership or initiation dues or fees). NERC Bylaws Article II, §1. In the *ERO Certification Order*, the Commission stated the availability of membership to any person or entity with an interest in the reliable operation of the North American BPS created an open membership structure that is consistent with the statutory requirement that the ERO establish rules that assure fair stakeholder representation. *ERO Certification Order* at P 54. Each member is assigned to one of the 12 membership sectors of NERC. NERC Bylaws Article II, §4.

[78] Article II, §4a of the NERC Bylaws specifies the types of persons or organizations that would be included in each of the membership sectors.

[79] The representation of Regional Entities in the MRC reflects changes made by NERC to the originally-proposed composition of the MRC in response to concerns expressed by the Commission in P 75 of the *ERO Certification Order*. *See NERC ERO Governance Compliance Filing* at 6-9. The Commission accepted these changes in an Order issued October 30, 2006. The Commission also accepted the overall structure and composition of the MRC in that Order. *North American Electric Reliability Corporation, Order on Petitions for Rehearing and Clarification; Order on Compliance Filing*, 117 FERC ¶ 61,126 (2006), at PP 30 and 44.

[80] The chairman and vice chairman of the MRC are selected annually by majority vote of the members of the MRC, and may not be from the same membership sector. Upon being selected as chairman and vice chairman, these individuals cease to be representatives of the MRC sectors to which they were originally elected, and are thereafter responsible to act in the best interests of the members of NERC as a whole. NERC Bylaws Article VIII, §5.

[81] Article VIII, §4 of the Bylaws contains provisions for the election of additional Canadian members to the MRC as and when necessary to ensure that the percentage of Canadian members on the MRC is approximately equal to the percentage the NEL of Canada is of the total NEL of the United States and Canada. See page 24 below for the definition of NEL.

(5) The following representatives of the government representatives sector: two representatives of the United States federal government, one representative of the Canadian federal government, two representatives of state governments, and one representative of a provincial government, all of whom shall be nonvoting members of the MRC except the two representatives of state governments.

The MRC is therefore comprised of 26 voting members when at full complement (or more if the election of additional Canadian members has been necessary in accordance with Article VIII, §4 of the Bylaws). The members of the MRC from each sector are nominated from, and elected by, the NERC members in that sector pursuant to the processes specified in Article VIII, §3 of the NERC Bylaws, which generally call for election of the two candidates from each sector receiving the highest numbers of votes in the sector. The members of the MRC are elected annually (or between annual elections if needed to fill a vacancy).[82]

In summary, NERC's trustees are nominated by a nominating committee comprised of independent trustees whose terms are not expiring, members of the MRC, and possibly others. NERC's trustees are elected by a two-thirds vote of the MRC, which is a committee established pursuant to the Bylaws to fairly represent the sectors of NERC's membership and is open to any person or entity with an interest in reliable operation of the North American BPS. Thus, the NERC Bylaws provide for fair stakeholder representation in the selection of NERC's trustees.

Balanced Decision-Making in any NERC Committee or Subordinate Organizational Structure

NERC's Bylaws authorize the Board of Trustees to create standing committees of NERC and such other committees as the Board deems necessary to carry out the purposes of NERC:

> In addition to those committees specified by these Bylaws, to which the board shall appoint members in accordance with the requirements of these Bylaws, the board may by resolution create standing committees of the Corporation; and may in addition by resolution appoint such other committees as the board deems necessary to carry out the purposes of the Corporation. *The board shall appoint standing committees and other committees of the Corporation that are representative of members, other interested parties and the public, that provide for balanced decision making, and that include persons with outstanding technical knowledge and experience. All appointments of committees of the Corporation shall provide the opportunity for an equitable number of members from the United States and Canada (and from Mexico after the Corporation receives recognition by appropriate governmental authorities in Mexico as its electric reliability organization) to be appointed to each committee in approximate proportion to each country's percentage of the total NEL*. All committees shall have such scope and duties, not inconsistent with law, as are specified in these Bylaws and the Rules of

[82] NERC Bylaws Article VIII, §3.

> Procedure of the Corporation or otherwise determined by the board. (Emphasis added.)[83]

Section 1300 of the NERC ROP provides additional criteria for the creation and appointment of NERC standing committees. In creating a standing committee, the NERC Board of Trustees must approve the charter of the committee and assign specific authority to each committee necessary to conduct business within its charter.[84] Each committee shall have a defined membership composition that is explained in its charter. The specified committee membership composition can provide for balanced decision-making (i) by providing for representatives from each sector of the NERC membership, or (ii) where sector-based membership will not bring together the necessary diversity of opinions, technical knowledge and experience in a particular subject area, by bringing together a wide diversity of opinions from industry experts with outstanding technical knowledge and experience in a particular subject area.[85] Committee membership shall also provide the opportunity for an equitable number of members from the United States and Canada, based approximately on proportionate NEL.[86]

The NERC ROP require that committee members shall be selected in a manner that is open, inclusive, and fair.[87] Unless otherwise stated in the NERC ROP or approved by the NERC Board of Trustees, all committee member appointments are to be approved by the board, and committee officers are to be appointed by the Chairman of the Board.[88]

Further, the NERC ROP require that all NERC committees and other subgroups (except for those organized on other than a sector basis because sector representation will not bring together the necessary diversity of opinions, technical knowledge, and experience in a particular subject area) must ensure that no two stakeholder sectors are able to control the vote on any matter,

[83] NERC Bylaws Article VII, §1. "Committees specified by these Bylaws" include the MRC and the Nominating Committee for the NERC Board of Trustees (discussed above under "fair stakeholder representation in the selection of NERC's trustees"), and the Personnel Certification Governance Committee (PGCC) provided for in Article XII of the Bylaws. The purpose of the PGCC is to provide oversight to the policies and processes used to implement and maintain the integrity and independence of the NERC System Operator Certification Program. NERC Bylaws Article XII, §1. The members of the PGCC are appointed by the Board from candidates nominated by a nominating task force; nominations and appointments are to take into account the need to include representatives of all geographic regions of North America on the PGCC. *Id*., Article XII, §2. In addition to the aforementioned committees, NERC standing committees include the Standards Committee, Compliance and Certification Committee, Critical Infrastructure Protection Committee, Operating Committee, Planning Committee, and the Reliability Issues Steering Committee.

[84] ROP §1301.

[85] ROP §1302.

[86] ROP §1302.

[87] ROP §1303.

[88] ROP §1303.

and no single sector is able to defeat a matter.[89] Any committees and subgroups organized on other than a membership-sector basis must be reported to the NERC Board of Trustees and the MRC, along with the reason for constituting the committee or subgroup in the manner chosen. The ROP provide that for any committee or subgroup organized on other than a membership-sector basis, a reasonable opportunity for additional participation (as members or observers) shall be provided for sectors not represented on the committee or subgroup (subject to any reasonable restrictions as may be necessary to accomplish the mission of the committee or subgroup).[90] Additionally, a reasonable opportunity must be provided for membership from sectors desiring to participate in any committees and subgroups pertaining to development of, interpretation of, or compliance with Reliability Standards.[91]

The NERC ROP provide that NERC standing committees may appoint subgroups using the same principles as specified in §1302 of the ROP (summarized in the immediately preceding paragraph).[92]

The provisions of §§1301 and 1302 of the NERC ROP regarding committee composition reflect revisions to these provisions that were approved or directed by the Commission in its October 30, 2006 order on the *NERC ERO Governance Compliance Filing*.[93]

The requirement for balanced decision-making is also applicable to the Reliability Standards development process, and is discussed below under criterion 5, "The ERO has established rules that provide reasonable notice and opportunity for public comment, due process, openness and balance of interests in developing Reliability Standards, and otherwise exercising its duties."

C. Criterion 3 - The ERO has established rules that allocate equitably reasonable dues, fees and charges among end users for all statutory activities.

NERC's Bylaws require that the funding mechanism used to recover its net annual budget requirement (i.e., net of fees and other revenues received by NERC from users and purchasers of NERC products and services, and net of prior-period funding surplus or deficiency) "shall consist of such assessments as determined by the [NERC] board that result in an equitable allocation of the Corporation's funding requirement among end users of the North American electric utility system as established in the Corporation's Rules of Procedure."[94] Section 1102 of the NERC ROP,

[89] ROP §1302.

[90] ROP §1302.

[91] ROP §1302.

[92] ROP §1305.

[93] *See North American Electric Reliability Corporation, Order on Petitions for Rehearing and Clarification; Order on Compliance Filing*, 117 FERC ¶ 61,126 (2006), at PP 75-87.

[94] NERC Bylaws Article XIII, §3. NERC charges users/purchasers of some of its products and services directly for the products and services, at prices that cover some or all of the cost of providing the product or service. Examples include charges to purchasers of data sets from the Generating Availability Data System, charges to candidates for

"NERC Funding and Cost Allocation," prescribes the allocation methods to be used to recover NERC's funding requirements among regions of the United States and among countries in the North American BPS. Section 1102 specifies that NEL shall be used to allocate funding requirements among interconnections and Regional Entities except in those instances in which direct assignment of costs to a particular interconnection, Regional Entity, or group of entities is appropriate; however, in the case of direct assignment, NEL must be used to allocate the directly-assigned costs within the interconnection, Regional Entity, or group of entities:

> (1) In order that NERC's costs shall be fairly allocated among Interconnections and among Regional Entities, the NERC funding mechanism for all statutory functions shall be based on NEL.
>
> (2) NERC's costs shall be allocated so that all load (or, in the case of costs for an Interconnection or Regional Entity, all load within that Interconnection or Regional Entity) bears an equitable share of such costs based on NEL.
>
> (3) Costs shall be equitably allocated between countries or Regional Entities thereof for which NERC has been designated or recognized as the Electric Reliability Organization.
>
> (4) Costs incurred to accomplish the statutory functions for one Interconnection, Regional Entity, or group of entities will be directly assigned to that Interconnection, Regional Entity, or group of entities provided that such costs are allocated equitably to end-users based on NEL.

The NERC ROP define NEL as:

> [N]et generation of an electric system plus energy received from others less energy delivered to others through interchange. It includes system losses but excludes energy required for the storage of energy at energy storage facilities.[95]

In business plan and budget filings with the Commission, actual assessments for Canadian and Mexican entities vary after taking into account polices regarding the allocation of certain compliance and enforcement costs.

D. Criterion 4 - The ERO has established rules that provide fair and impartial procedures for enforcement of Reliability Standards through the imposition of penalties in accordance with 18 C.F.R. §39.7, including limitations on activities, operations, or other appropriate sanctions or penalties.

NERC has established rules that provide fair and impartial procedures for monitoring and enforcement of compliance with Reliability Standards. These rules and procedures are embodied

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certification as NERC-certified operators for examinations and for renewal of credentials, and charges to continuing education providers for certification of their education programs.

[95] ROP Appendix 2.

primarily in §400 of the NERC ROP, the NERC CMEP (Appendix 4C to the ROP), and individual Regional Entity CMEPs (which conform generally to the NERC CMEP), all of which have been approved by the Commission. These rules and procedures were discussed in detail above under criterion 1, relating to the ERO's ability to develop and enforce Reliability Standards that provide for an adequate level of reliability of the BPS. As discussed above under criterion 1, §400 of the ROP, and the NERC uniform CMEP, include provisions for avoidance of conflicts of interest on the part of the CEA personnel conducting compliance monitoring processes, provisions for notice to registered entities and opportunity to respond to compliance monitoring processes, and provisions allowing registered entities to engage in settlement discussions with the CEA concerning notices of alleged violations, proposed penalties or sanctions, and mitigation plans.

In addition, Attachment 2, *Hearing Procedures*, to the uniform CMEP contains detailed due process procedures for the conduct of hearings before the CEA hearing body, when requested by the registered entity, concerning a disputed notice of alleged violation and/or proposed penalty or sanction, disputed mitigation plan provisions, or disputed remedial action directive. The *Hearing Procedures*, which were initially approved by the Commission in two orders, subject to various specific compliance requirements,[96] are based on, and in most respects are quite similar to, the Commission's Rules of Practice and Procedure[97] and to the rules of practice and procedure used by many state public utility commissions.

In 2013, the Regional Entity representatives to the ERO Legal Group developed *Hearing Body Manual – Guidance for Conducting Hearings at the Regional Entities* (Hearing Body Manual) to provide practical guidance to hearing body members at the eight Regional Entities regarding the hearing process. The Hearing Body Manual outlines the specific duties of the hearing officer and the hearing body and discusses the standard of review that should govern the hearing body's consideration of the hearing officer's decisions throughout the hearing process. The particulars of the hearing process, including the roles of the hearing officer and the hearing body, are set forth in Attachment 2 to the CMEP. To the extent that there is a conflict between the Hearing Body Manual and the CMEP, the CMEP, as applicable, prevails.

The remainder of this discussion of NERC's compliance with criterion 4 addresses NERC's rules and procedures for the determination and imposition of penalties for violations of Reliability Standards.

Section 215(e)(6) of the FPA, and §39.7(g) of the Commission's regulations,[98] requires that any penalty imposed for violation of a Reliability Standard shall (a) bear a reasonable relation to the seriousness of the violation; and (b) take into consideration the efforts of the user, owner or

[96] *Order Addressing Revised Delegation Agreements*, 122 FERC ¶61,245 (2008); *Order Accepting Compliance Filings, Subject to Conditions*, 125 FERC ¶61,330 (2008).

[97] 18 C.F.R. Part 385.

[98] 18 C.F.R. §39.7(g).

operator to remedy the violation in a timely manner.[99] This fundamental requirement is embodied in §401.7 of the NERC ROP and in §3.8 of the NERC *Sanction Guidelines*, Appendix 4B to the ROP. Section 39.7(c) of the Commission's regulations[100] requires that NERC or a Regional Entity may, after notice and opportunity for hearing, impose a penalty on a user, owner or operator of the BPS for a violation of a Reliability Standard if NERC files a notice of penalty and record of the proceedings with the Commission and serves a copy on the user, owner or operator. The notice of penalty must contain: (i) the name of the entity on whom the penalty is imposed; (ii) identification of each Reliability Standard violated; (iii) findings of fact with respect to any act or practice resulting in violation of the standard; (iv) a description of the penalty imposed; (v) the record of the proceeding; and (vi) any other matters NERC or the Regional Entity may find relevant.[101] The penalty may not take effect earlier than the 31st day after NERC files the notice of penalty and record of proceeding with the Commission,[102] and it is subject to review by the Commission on its own motion or on application of the user, owner or operator.[103] Section 5.9 of the NERC CMEP provides for the filing of a notice of penalty with the Commission, and for a 30-day period to run before the penalty becomes effective, in accordance with 18 C.F.R. §39.7(d) through (e).[104]

Section 39.7(g) of the Commission's regulations[105] requires the ERO to submit for Commission approval penalty guidelines that set forth a range of penalties for violations of Reliability Standards, and specifies that a penalty imposed by the ERO or a Regional Entity must be within the range set forth in the penalty guidelines. The NERC *Sanction Guidelines* comprise the penalty guidelines established by NERC, which the Commission has approved pursuant to §39.7(g).

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[99] 18 C.F.R. §39.7(g)(1) also specifies that a penalty may be monetary or non-monetary, and may include, but is not limited to, a limitation on an activity, function, operation, or other appropriate sanction, including being added to a reliability watch list composed of major violators that is established by the ERO, a Regional Entity or the Commission.

[100] 18 C.F.R. §39.7(c).

[101] 18 C.F.R. §39.7(d).

[102] 18 C.F.R. §39.7(e).

[103] 18 C.F.R. §39.7(e).

[104] Certain instances of noncompliance with the Reliability Standards may be resolved outside of the notice of penalty process set forth in the NERC CMEP. Beginning in September 2011, NERC began tracking certain lesser-risk remediated possible violations in the FFT program. Following the Commission's *Order Accepting with Conditions the Electric Reliability Organization's Petition Requesting Approval of New Enforcement Mechanisms and Requiring Compliance Filing*, 138 FERC ¶ 61,193 (2012), the Commission considered all FFT matters closed sixty days after the FFT informational filing was submitted to the Commission unless the Commission sought to review a specific matter. In June 2013, the Commission approved expanding the scope of the FFT Program to include a limited pool of moderate risk issues (in addition to the minimal risk issues already permitted under the program), as well as issues with ongoing mitigation activities, provided the mitigation would be completed within 90 days. In addition, the Commission approved the practice of publicly posting FFT matters on a common website in lieu of a monthly informational filing to the Commission. The Commission indicated that it would consider an FFT matter closed 60 days following the public posting. *Order on Compliance Filing*, 143 FERC ¶ 61,253 (2013).

[105] 18 C.F.R. §39.7(g)(2).

Under the *Sanction Guidelines*, penalties are to be commensurate to the reliability impact of the violation and to those levied for similar violations, while still reflecting unique facts and circumstances related to the violation or the violator. NERC is charged with ensuring "acceptable similarity" in penalties for comparable violations.[106]

Significantly, however, the *Sanction Guidelines* also state, "Any provisions within a settlement regarding Penalties or sanctions can supersede any corresponding Penalties or sanctions that would otherwise be determined pursuant to these Sanction Guidelines."[107] As such, the negotiation of settlements and determination of penalties involve compromise and the weighing of multiple considerations to arrive at a penalty agreeable to the Regional Entity and the registered entity. Even with this available flexibility, NERC still evaluates the facts and circumstances of every violation that is part of a settlement to ensure that the penalty for that violation, and for the group of violations in the settlement, is within a range of reasonableness that displays consistency.

When evaluating every violation, NERC starts with a base penalty amount that is provided by the VRF/VSL matrix. If the registered entity has a previous violation of a same or similar Reliability Standard Requirement, then the penalty may be aggravated.[108] NERC next considers the violation time horizon for the violation, with multipliers applied to the penalty based on the effect on operations. The highest multiplier applies to real-time operations, while long-term planning is on the opposite end of the spectrum. The registered entity's ability to impact reliability determines the next multiplier, with small facilities or entities having their penalty reduced by a significant amount. A multiplier can be applied based on the condition of the BPS at the time of the violation, with aggravation for a violation occurring during stressed conditions.[109] Among the mitigating factors in penalty determination are the quality of the registered entity's internal compliance program, the degree of the registered entity's cooperation in resolution of the violation, and whether the registered entity self-reported the violation.[110]

NERC will aggregate the results of the violation-by-violation analysis for comparison with the penalty included in the settlement submitted by the Regional Entity. NERC also evaluates how the penalty for the violations in the instant settlement compares to penalties for similar violations included in settlements that have already been approved by NERC and subject to review by the Commission. The evaluation of settlements provides an evolving store of knowledge to use when considering new settlements submitted to NERC. In the end, if the penalty included in the settlement falls within a range of reasonableness for penalties associated with violations involving similar reliability risks, similar entities, and similar facts and circumstances, then the penalty is deemed consistent enough for approval by NERC.

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[106] *Sanction Guidelines* §1.

[107] *Sanction Guidelines* §2.1.

[108] *Sanction Guidelines* §§3.1 and 3.2.

[109] *Sanction Guidelines* §2.7; *see also* §3.2.

[110] *Sanction Guidelines* §3.3.

E. Criterion 5 - The ERO has established rules that provide reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing Reliability Standards, and otherwise exercising its duties.

NERC has established rules that provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing Reliability Standards, and otherwise exercising its duties. With respect to the development of Reliability Standards, NERC's Bylaws require that:

> The Corporation shall develop Reliability Standards pursuant to procedures and processes that shall be specified in the Rules of Procedure of the Corporation. The Rules of Procedure shall provide for the development of Reliability Standards through an open, transparent, and public process that provides for reasonable notice and opportunity for public comment, due process, and balancing of interests and is designed to result in Reliability Standards that are technically sound. Participation in the process for developing Reliability Standards shall not be limited to members of the Corporation but rather shall be open to all persons and entities with an interest in the reliable operation of the BPS.[111]

NERC's process for developing and modifying Reliability Standards, which the Commission accepted as meeting the criteria for certifying NERC as the ERO pursuant to §215 of the FPA and §39.3(b) of the Commission's regulations,[112] is embodied in §300 of the NERC ROP and the SPM, Appendix 3A to the ROP. Section 304 of the ROP states that NERC shall develop Reliability Standards in accordance with the NERC SPM. The SPM sets forth the detailed process steps for development and approval of a new Reliability Standards or revision to a Reliability Standard.

Section 304 of the NERC ROP sets forth NERC's "Essential Principles for the Development of Reliability Standards," which include openness, transparency, consensus-building, fair balance of interests, due process, and timeliness:

> 1. **Openness** — Participation shall be open to all persons who are directly and materially affected by the reliability of the North American BPS. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in NERC or any other organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.
>
> 2. **Transparency** — The process shall be transparent to the public.

[111] NERC Bylaws Article IX, §2.

[112] *ERO Certification Order*, 116 FERC ¶61,062, at PP 239, 241, 250.

3. **Consensus-building** — The process shall build and document consensus for each standard, both with regard to the need and justification for the Reliability Standard and the content of the Reliability Standard.

4. **Fair Balance of Interests** — The process shall fairly balance interests of all stakeholders and shall not be dominated by any two segments as defined in Appendix 3D, *Development of the Registered Ballot Body*, of these Rules of Procedure, and no single segment, individual or organization shall be able to defeat a matter.

5. **Due Process** — Development of Reliability Standards shall provide reasonable notice and opportunity for any Person with a direct and material interest to express views on a proposed Reliability Standard and the basis for those views, and to have that position considered in the development of the Reliability Standards.

6. **Timeliness** — Development of Reliability Standards shall be timely and responsive to new and changing priorities for reliability of the BPS.

Section 305 of the NERC ROP specifies that "NERC Reliability Standards shall be approved by a Registered Ballot Body prior to submittal to the [NERC] Board and then to [a]pplicable [g]overnmental [a]uthorities for their approval," and that "[a]ny person or entity may join the Registered Ballot Body to vote on Reliability Standards." The RBB is organized on an industry segment basis, and persons or organizations joining the RBB must select membership in the appropriate segment (subject to periodic review by NERC).[113] The RBB segments and the criteria for membership in each segment are set forth as follows:[114]

- Segment 1: Transmission Owners
- Segment 2: Regional Transmission Organizations and Independent System Operators
- Segment 3: Load-Serving Entities
- Segment 4: Transmission Dependent Utilities
- Segment 5: Electric Generators

[113] ROP §305.

[114] ROP Appendix 3D at 2-3. The segments of the RBB are different from the NERC membership segments established by Article II, §4 of the NERC Bylaws (discussed above under criterion 2). The Commission approved the use of segments for the RBB that are different from the NERC membership segments. *North American Electric Reliability Corporation, Order on Petitions for Rehearing and Clarification, Order on Compliance Filing*, 117 FERC ¶ 61,126 (2006), at P 30.

- Segment 6: Electricity Brokers, Aggregators, and Marketers
- Segment 7: Large Electricity End Users
- Segment 8: Small Electricity Users
- Segment 9: Federal, State, and Provincial Regulatory or other Government Entities
- Segment 10: Regional Entities

Section 306 of the ROP provides for the standards development process to be overseen by a Standards Committee, which is an elected body comprised of two members of each segment of the RBB and two officers elected to represent the interests of the industry as a whole.[115] The Standards Committee is to ensure stakeholder interests are fairly represented in the Reliability Standards development process. Section 308.2 of the ROP specifies that proposed Reliability Standards or revisions to Reliability Standards shall be submitted to the NERC Board of Trustees for approval after being approved by the RBB pool voting on the standard.

The NERC SPM sets out the detailed steps in the process for developing and approving Reliability Standards or revisions to Reliability Standards. The process is based on the procedures of the ANSI and other standards-setting organizations in the United States and Canada.[116] The standards development process is intended to develop consensus on both the need for and content of a proposed standard.[117] As detailed in the SPM, the process includes the following key elements:

- Nomination of a proposed standard, revision to a standard, or withdrawal of a standard, using a SAR, which may entail appointing a SAR drafting team.[118]
- Public posting of the SAR to allow interested persons and entities to review and comment on the need for the proposed standard and the expected outcomes and impacts from implementing it, and to identify if there is stakeholder consensus on the need, scope and applicability of the standard proposed by the SAR.[119]

[115] Election of the members of the Standards Committee is governed by the *Procedures for Election of Members of the Standards Committee*, Appendix 3B to the ROP.

[116] SPM §§1.4, 10.0, 13.0, and 16.0. ANSI accredited NERC's Reliability Standards development process in 2003.

[117] SPM §§1.4. 3.8, 3.10, and 4.0.

[118] SPM §§4.0, 4.2, and 4.3.

[119] SPM §§4.0, 4.1, and 4.2.

- Review of the public comments in response to the SAR and prioritization of proposed standards, leading to authorization to develop standards for which there is a stakeholder consensus-based need.[120]

- Appointment of a standard drafting team to draft the new or revised standard. The appointed standard drafting team is to have the expertise, competencies and diversity of views needed to develop the standard. The appointment process includes a public solicitation for nominees.[121]

- Drafting the new or revised standard. The standard will be drafted by the standard drafting team with the assistance and administrative support of the NERC standards process manager (a NERC professional staff member), who will review the draft standard for consistency of quality and completeness and to ensure the standard is within the scope and purpose identified in the SAR.[122]

- Public posting of the draft standard to allow interested parties to review and comment on it, to receive specific comments from interested parties on the text of the standard, to assess stakeholder consensus on the draft standard, and to determine if the draft standard should be modified to increase consensus.[123]

- Field testing (if any) of the draft standard and its measures.[124]

- Analysis of public comments and field test results (if any) by the standard drafting team, giving consideration to the written views and objections of all participants, to determine if there is consensus the proposed standard should go to ballot, or requires further work.[125]

- Balloting of the standard by the industry stakeholder ballot pool formed from the RBB for purposes of balloting the new or revised standard.[126] (The voting process is described below.)

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[120] SPM §§4.0, 4.1, 4.2, and 4.3.

[121] SPM §§4.0, 4.3, and 4.4.

[122] SPM §§4.0 and 4.4.

[123] SPM §§4.0, 4.5, and 4.7.

[124] SPM §§4.0 and 6.0.

[125] SPM §§4.0, 4.5, 4.6, 4.7, 4.12, and 6.0.

[126] SPM §§4.0, 4.7, 4.8, and 4.9.

- Re-balloting of the standard to consider specific comments by those submitting negative votes with comments.[127]

- Vote by the NERC Board of Trustees to approve or reject the standard that has been approved by the ballot pool. The NERC Board of Trustees may adopt or reject a Reliability Standard that has been approved by the ballot pool, but may not modify the standard; however, if the NERC Board of Trustees chooses not to adopt a proposed standard, the board shall provide its reasons.[128]

- Submission of the RBB-approved and board-approved Reliability Standard to the Commission and other applicable governmental authorities for approval.[129]

As provided in the SPM, voting on a proposed Reliability Standard or revision to a standard is done by the RBB ballot pool formed for that standard, and is tallied on a weighted segment basis. At least 30 days prior to the start of a ballot, the NERC standards process manager issues a notice to the entities in the RBB advising them of the upcoming ballot on the new or revised standard, so that entities may elect to join the ballot pool for balloting the standard. Any member of the RBB may join (or leave) the ballot pool for the standard until the ballot period begins.[130] The balloting is conducted electronically with voting allowed during a specified ballot period, typically 10 days.[131] Approval of a proposed standard or revision to a standard requires both (i) a quorum, which is established by at least 75 percent of the members of the ballot pool submitting a response with an affirmative vote, a negative vote, or an abstention,[132] and (ii) affirmative votes by a two-thirds majority of the weighted segment votes.[133] The calculation of the weighted segment voting results is described in detail in the SPM.[134]

The foregoing demonstrates that NERC's rules provide reasonable notice and opportunity for public comment, due process, openness, and balance of interests in the development of

[127] SPM §§4.0, 4.13, and 4.14. Voters on the first ballot are allowed to submit comments with affirmative ballots and reasons for their votes with negative ballots (although inclusion of a statement of reasons with a negative ballot is not required).

[128] SPM §§4.0, 4.15, and 4.16.

[129] SPM §§4.0, 4.16, and 4.17.

[130] SPM §4.8.

[131] SPM §§4.0 and 4.9.

[132] SPM §4.10.

[133] SPM §§4.10 and 4.11. For this purpose the number of votes cast is the sum of the affirmative and negative votes cast by the ballot pool, excluding abstentions, non-responses and negative votes without comments.

[134] SPM §§4.10 and 4.11.

Reliability Standards. In finding that NERC met the statutory and regulatory criteria to be certified as the ERO, the Commission found NERC's Reliability Standards development process met the ERO certification requirement that the ERO candidate have rules providing for reasonable notice and opportunity for public comment, due process, openness, and balancing of interests in developing Reliability Standards.[135]

Other NERC rules provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in the exercise of NERC's duties other than developing Reliability Standards. As discussed under criterion 2 above, NERC's Bylaws provide for its trustees to be elected by the MRC, which (again per the NERC Bylaws) is comprised of representatives of the sectors of the NERC membership as defined in the Bylaws. The Bylaws also provide that amendments to the Bylaws must be adopted by majority vote of both the Board of Trustees and the MRC, conducted after at least 10 days and no more than 60 days' notice of the vote on the proposed amendment. Additionally, the NERC membership may adopt new Bylaws, or alter, amend, or repeal amendments adopted by vote of the board and the MRC, by vote of two-thirds of the sectors voting on the alteration, amendment, repeal or adoption.[136]

The Bylaws further provide that revisions to the NERC ROP may be proposed by: (i) any 50 members of NERC, which must include members from at least three membership sectors; (ii) the MRC; (iii) a committee of NERC to whose function and purpose the ROP to be amended pertains; or (iv) an officer of NERC. A proposed revision to the NERC ROP must be posted on the NERC website for public comment for a minimum of 45 days prior to the NERC Board of Trustees vote on the proposed revision.[137]

The NERC Bylaws require that notice of meetings of the NERC Board of Trustees and of the MRC, and notice of calls for action without a meeting by the board or the MRC, along with all non-confidential materials to be considered by the board or MRC at a meeting or in an action without a meeting, shall be posted on the NERC website at least 24 hours prior to the meeting or within 24 hours after the call for action without a meeting.[138] The ROP provide that notice of meetings of NERC committees, and all non-confidential materials relating to the meeting, shall be posted on the NERC website at approximately the same time(s) the notice and materials are provided to the committee members.[139] Additionally, the Bylaws require that, except for discussions of certain specified non-public topics, meetings of the NERC Board of Trustees and of the MRC shall be open to the public (subject to reasonable space limitations).[140] Similarly, the

[135] *ERO Certification Order* at P 250.

[136] NERC Bylaws Article XIV, §1.

[137] NERC Bylaws Article XI, §2.

[138] NERC Bylaws Article V, §§4 and 6; Article VIII, §§10 and 12.

[139] ROP §1304.1.

[140] NERC Bylaws Article V, §4; Article VIII, §10.

NERC ROP require that, except for discussions of certain specified non-public topics, meetings of NERC standing committees shall be open to the public (subject to reasonable space limitations).[141]

With respect to the preparation of NERC's annual business plan and budget, the NERC Bylaws provide that NERC shall post a draft business plan and budget for comment by the NERC membership, the MRC, and the NERC standing committees for at least 30 days prior to the board meeting at which the annual business plan, budget and funding requirement is to be approved for submission to the Commission. The Board shall also consult with the members of the MRC on the proposed business plan and budget before it is adopted.[142] Should a supplemental or modified budget or assessment be considered for adoption during the course of the year, the Bylaws require that the procedures for posting, receipt of comments, and consultation with the MRC shall be followed to the extent possible in the board's judgment in light of the exigency of the circumstances necessitating preparation and approval of the supplemental or modified budget, funding and assessment.[143]

With respect to compliance monitoring and enforcement, as discussed above under criteria 1 and 4, the NERC CMEP and Regional Entity CMEPs, the NERC *Hearing Procedures* (Attachment 2 to the CMEP), and the NERC *Sanction Guidelines*, provide for reasonable notice to and due process for users, owners, and operators of the BPS in the conduct of compliance monitoring and enforcement activities of NERC and the Regional Entities. These activities include the implementation of the compliance monitoring processes, the conduct of hearings on disputed notices of alleged violations, proposed penalties, disputed mitigation plan components and disputed remedial action directives, and the imposition of penalties and sanctions for violations of Reliability Standards.

Finally, as discussed above under criterion 2, the NERC Bylaws and ROP require members to be selected for NERC standing committees and other committees and subgroups so as to (subject to specified exceptions) provide for balanced decision making, such that no two stakeholder sectors can control the voting on the committee and no single stakeholder sector is able to defeat a matter; and to provide the opportunity for an equitable number of members from the United States and Canada.

F. Criterion 6 - The ERO has established rules that provide appropriate steps to gain recognition in Canada and Mexico.

As stated in its Certificate of Incorporation, one of the corporate purposes of NERC is "to act as the electric reliability organization for the United States as certified by the Federal Energy Regulatory Commission and for Canada and Mexico as recognized by applicable government and regulatory authorities in such countries, all pursuant to law." The efforts of NERC to seek recognition in Canada and Mexico are described below.

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[141] ROP §1304.1.

[142] NERC Bylaws Article XIII, §4; *see also* ROP §1103.1.

[143] NERC Bylaws Article XIII, §5.

Canada

Under the Constitution of Canada, regulation of electricity is primarily within the jurisdiction of each province. Canada does not have a 'FERC-equivalent' with plenary jurisdiction over electricity matters, although the National Energy Board (NEB) does have jurisdiction over international power lines. Accordingly, beginning before its certification as the ERO for the United States and continuing to the present time, NERC has devoted significant efforts to developing relationships with each of the relevant provincial authorities, as well as the NEB. Where possible, NERC has devoted efforts attempting to obtain recognition as the electric reliability organization. NERC's progress in this regard is described below.

Alberta

Reliability Standards

The Alberta Electric System Operator (AESO) is the independent system operator, a statutory corporation pursuant to Alberta's *Electric Utilities Act*, *2003* (EUA).[144] AESO's statutory mandate requires that it direct the operation of the Alberta interconnected electric system, plan for the future of the transmission system, and operate the wholesale electricity market in the province.

Pursuant to the Alberta *Transmission Regulation* (made pursuant to the EUA),[145] Alberta Reliability Standards include reliability standards[146] enacted by WECC, NERC, or any similar entity that is recognized by the AESO, to the extent that these reliability standards are adopted by the AESO in accordance with the *Transmission Regulation*. The AESO also has the authority under the *Transmission Regulation* to adopt other reliability standards subject to certain process requirements.

In order for a reliability standard to be adopted in Alberta, the *Transmission Regulation* requires that the AESO consult with those market participants that it considers likely to be directly affected by one or more reliability standards and make a recommendation to the Alberta Utilities Commission to approve or reject the reliability standards being considered for approval. The Alberta Utilities Commission must follow the AESO's recommendation unless an interested person satisfies the Alberta Utilities Commission that the recommendation of the AESO is either "technically deficient" or "not in the public interest." When the AESO considers NERC Reliability Standards for adoption in Alberta, the AESO is required to determine whether the NERC

[144] Alberta's EUA is available at: http://www.qp.alberta.ca/documents/Acts/E05P1.pdf.

[145] Alberta's *Transmission Regulation* is available at: http://www.qp.alberta.ca/documents/Regs/2007_086.pdf.

[146] In this context, where not capitalized, the phrase "reliability standards" refers to standards relating to reliability generally, whether or not they were developed or approved by NERC.

Reliability Standards can be applied in Alberta, including whether approval would be appropriate for the Alberta electric energy market framework.[147]

The AESO's *Alberta Reliability Standards Program Work Plan* is intended to help manage and track the adoption of NERC Reliability Standards in Alberta. It was last revised in June 2014, and it reflects a risk-based prioritization approach.[148] The Alberta Reliability Standards, as approved, bear the same identifiers as the original NERC Reliability Standards (COM, BAL, FAC, etc.), but have an "AB" added to the name.[149]

An Alberta Reliability Standard may incorporate modifications from the original NERC Reliability Standard to recognize the physical characteristics of the Alberta system or for other reasons.[150]

When presented to the Alberta Utilities Commission by the AESO for approval, a proposed Alberta Reliability Standard will contain an explanation for any proposed modifications, which are not intended to change the intent or substance of the NERC Reliability Standards. Where there have been changes from a NERC Reliability Standard to an Alberta Reliability standard, it is noted in a quarterly update report that is provided to WECC and to NERC.

Effective January 1, 2014, the AESO assumed all responsibilities related to the functions of a Reliability Coordinator, effective January 1, 2014. The AESO has indicated that it remains an active member and supporter of the WECC (the former Reliability Coordinator for the AESO), and it looks forward to a strong working relationship with the proposed independent WECC RC, Peak Reliability. Additional Alberta Reliability Standards will be adopted, and this work is underway.

Data Sharing

Under §8.4 of the WECC/AESO membership and operating agreement (MOA), if WECC determines that the AESO is not in compliance with an Alberta Reliability Standard, WECC must promptly refer the matter to the Market Surveillance Administrator (MSA). Pursuant to the

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[147] Alberta has developed an Alberta Functional Model that integrates with the Alberta regulatory and market framework. The Alberta Functional Model defines entity types that perform functions that impact the reliability of the transmission system. Functional entity types are used to identify if an Alberta Reliability Standard is applicable to that functional type.

[148] The *Alberta Reliability Standards Program Work Plan* can be found at: http://www.aeso.ca/rulesprocedures/25052.html. Alberta Reliability Standards currently in effect and their effective dates are listed on the AESO website at: http://www.aeso.ca/rulesprocedures/17006.html. A number of NERC Reliability Standards have been rejected as not being applicable to entities in Alberta. These are listed at: http://www.aeso.ca/rulesprocedures/16426.html.

[149] An example of a current Alberta Reliability Standard is BAL-001-AB-0a, Real Power Balancing Control Performance.

[150] *See* Project Charter for Alberta Reliability Standards Implementation at p.1, available at: http://www.aeso.ca/downloads/ARS_Project_Charter_2011-12-05_final.pdf.

WECC/MSA services agreement, WECC, on behalf of the MSA, will monitor AESO's compliance with Alberta Reliability Standards and report its findings to the MSA.

Sections 2.13, 6.1, and 6.5 of the WECC/MSA services agreement address WECC's ability to report possible violations[151] to NERC. Under §2.13, NERC and FERC are not allowed to participate in or observe WECC's actions taken according to the WECC/MSA services agreement, without the express approval of the MSA. Section 6.1 establishes that all records pertaining to WECC's services will be considered confidential and should be treated as strictly confidential at all times.[152]

Based on its agreement with the MSA, WECC is prohibited from disclosing information related to the AESO's compliance with Alberta Reliability Standards without the permission of the MSA. However, as noted in the NERC/WECC/AESO memorandum of understanding (MOU),[153] disclosing information related to confirmed contraventions would occur as such information is made public by the Alberta Utilities Commission. In addition, as there is value to the North American electric industry of receiving information on lessons learned from such contraventions, the AESO will work with NERC and WECC to provide information on lessons learned as made public by the Commission.

Compliance

The NERC/WECC/AESO MOU commits the AESO to appropriate compliance monitoring and enforcement "in a manner determined in Alberta." With regard to entities (other than the AESO) that are subject to Alberta Reliability Standards, the AESO carries out its mandate to monitor compliance according to a compliance monitoring plan. Matters of noncompliance with an Alberta Reliability Standard must be referred by the AESO to the MSA for consideration and possible action.

The Alberta Utilities Commission adopted specified penalties for contraventions of Alberta Reliability Standards effective November 2010. If warranted, the MSA is empowered by §52 of the *Alberta Utilities Commission Act* to issue a notice of specified penalty for contravention of an Alberta Reliability Standard. Specified penalties are defined in AUC Rule 027 and range from $500 to $25,000, depending upon the severity of the contravention and the applicable Alberta

[151] The terms "possible violation," confirmed violation," and "violation" are not defined in Alberta. Rather, Alberta uses the terms "suspected contravention" and "contravention."

[152] Section 6.5 is even more explicit with respect to WECC's authority to share information with NERC and mandates the following:

> WECC further acknowledges that this Agreement clearly stipulates that in no event will Confidential Records received or generated by WECC in respect of the Services or this Agreement be disclosed or made available to persons outside WECC, including to any representative of FERC, NERC or any other person, without the express written approval of the MSA.

[153] MOU between NERC, WECC, and AESO, effective July 15, 2010, at p. 7, available at: http://www.nerc.com/files/NERC-WECC-AESO_MOU_Executed%20Version_071510.pdf.

Reliability Standard.[154] Specified penalties can be appealed to the Alberta Utilities Commission. Alternatively, the MSA can pursue an administrative penalty before the Alberta Utilities Commission. The maximum administrative penalty amount is $1 million per day on which a contravention occurs or continues.

British Columbia

Reliability Standards

The British Columbia Utilities Commission (BCUC) is an independent, quasi-judicial regulatory agency that operates under and administers the *Utilities Commission Act*.[155] The BCUC adopts or rejects reliability standards in British Columbia and is responsible for the administration of the Mandatory Reliability Standards Program. The British Columbia Hydro and Power Authority (BC Hydro), a provincial crown corporation, is a regulated integrated utility and transmission provider that acts as a balancing authority and applicant for Reliability Standards to the BCUC.

To provide the necessary information required for determinations and in accordance with the *Utilities Commission Act*, BC Hydro submits a *Mandatory Reliability Standard Assessment Report* to the BCUC assessing the new and revised reliability standards adopted in the United States by FERC within the annual assessment period (December 1 to November 30). The assessment report is developed in consultation with Registered Entities in the Mandatory Reliability Standards Program. Further, in consultation with stakeholders regarding the estimated time required for the entities to implement and come into compliance with the reliability standards, BC Hydro suggests effective dates for each of the Reliability Standards assessed. After a public comment process, the BCUC reviews BC Hydro's analysis and then may either approve or reject Reliability Standards. The BCUC does not have authority to alter or amend a standard. To date no standards have been rejected, although the provincial process can lead to delays before a FERC-approved Reliability Standard is adopted.

In Order G-171-10, issued on November 25, 2010, the BCUC approved an annual Implementation Plan created by WECC for 2011 that includes "a list of minimum [R]eliability [S]tandards to be actively monitored, methods to be used for monitoring, an Audit Plan, Self-Certification Program and Schedule, Periodic Information Submittal requirements and Exception Reporting process."[156] The BCUC has also issued orders approving annual Implementation Plans for subsequent years.[157]

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[154] The specified penalties for contravention of Alberta Reliability Standards are available at: http://www.auc.ab.ca/rule-development/rule-027-specified-penalties-for-reliability-standards/Pages/default.aspx.

[155] The *Utilities Commission Act* is available at: http://www.bclaws.ca/Recon/document/ID/freeside/00_96473_01.

[156] Order No. G-171-10, issued by the BCUC, at p. 1, available at: http://www.bcuc.com/Documents/Orders/2010/DOC_26511_G-171-10_MRS-2011-Implementation-Plan.pdf.

[157] *See*, e.g., Order No. R-39-13, available at: http://www.bcuc.com/Documents/Orders/2013/DOC_38047_R-39-13_BC-Reliability_2014-Implementation-Plan.pdf (approving the Implementation Plan for the 2014 calendar year).

The standards in effect in British Columbia are generally listed in an attachment to the most recent order approving new or amended standards. NERC Reliability Standards and WECC regional Reliability Standards effective in British Columbia are also listed on the WECC website.[158] British Columbia has vested the BCUC with authority to levy monetary penalties for violations.

Data Sharing

WECC's relationship with the BCUC is governed by the Administration Agreement between the parties (dated October 8, 2009), the BCUC's *Rules of Procedure for Reliability Standards in British Columbia* (BCUC ROP), and BCUC's compliance monitoring program.[159] Under §3.2 of the Administration Agreement, WECC is required to immediately advise the BCUC and an applicable entity who has provided information to WECC if that information has been requested by NERC or a foreign government agency, unless disclosure of the request is prohibited by law. Therefore, WECC can only disclose confidential information related to possible violations if the BCUC approves the disclosure or by compulsion of law.

Under §6.3.1 of the BCUC ROP, the BCUC, in its discretion and upon request, may designate information as restricted.[160] If such designation is made, §3.6 of the Administration Agreement and the BCUC ROP prohibit WECC from transmitting the information outside of British Columbia. WECC can review the restricted information only at the offices of the applicable entity or at the BCUC. The applicable entity is not required to give WECC a copy of the restricted documents.

Under §3.1 of the Administration Agreement, WECC shall maintain the confidentiality of the confidential information and shall not disclose it even under conditions of confidence, except as provided in the Rules of Procedure, namely with BCUC approval. Section 3.1.1(ii) also prohibits WECC from disclosing documents or portion of documents that would potentially identify the source of the information. Finally, WECC cannot disclose any information if the BCUC directs WECC to keep it confidential.

Compliance

Under a contract with the BCUC, WECC performs compliance oversight for the province, including registration, monitoring and auditing functions and activities. However, the violations, enforcement, and penalty assessment functions remain with BCUC. Until recently, the BCUC had no monetary sanctions authority. BCUC now has authority to assess fines of up to $1 million per day. The process for imposing penalties for confirmed violations of reliability standards is under development.

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[158] *See* http://www.wecc.biz/Standards/BCApproved%20Standards/Forms/AllItems.aspx.

[159] *See* Attachments 1 and 2 to Order No. G-123-09, issued by the BCUC, available at: http://www.bcuc.com/Documents/Orders/2009/DOC_23219_G-123-09_BCUC%20MRS.pdf.

[160] *See* http://www.bcuc.com/Documents/MRS/Rules-of-Procedure.pdf.

Manitoba

Reliability Standards

The *Manitoba Hydro Act* establishes the framework for Manitoba Hydro to adopt NERC Reliability Standards by authorizing Manitoba Hydro, subject to Lieutenant Governor in Council approval, to adopt:

> in whole or in part, any standards, rules, terms, conditions, guidelines or schedules, which are related to the planning, design or operation of generation or transmission facilities within an integrated regional power grid, established by [the North American Electric Reliability Council, Mid-Continent Area Power Pool or…] an industry organization, regional transmission group, regulatory body or other association or group or any other person.[161]

The *Manitoba Hydro Amendment and Public Utilities Board Amendment Act (Electricity Reliability)*[162] and its implementing regulations, which came into force on April 1, 2012, set the basis for the adoption of mandatory and enforceable NERC Reliability Standards in Manitoba. This legislation gives the Public Utilities Board of Manitoba (PUB) the authority to make determinations of noncompliance with Reliability Standards, to impose sanctions, and to remand a standard to NERC for reconsideration.

On April 1, 2012, all then-current NERC Reliability Standards became mandatory and enforceable in Manitoba. These standards are listed in Schedule 1 to the *Reliability Standards Regulation*.[163] The province reserved the right to adopt new or amended standards by regulation. The government is consulting with stakeholders as to the best process for considering and approving standards for application in Manitoba.

Compliance

The *Compliance Monitoring and Enforcement Program Province of Manitoba*, based on the NERC CMEP, was adopted as Schedule 2 to the *Reliability Standards Regulation*. MRO and NERC, as compliance bodies, will monitor Manitoba Hydro's compliance with NERC Reliability Standards. If a compliance body alleges that a violation of standards has occurred in Manitoba, it must apply to the PUB with a recommended enforcement action for a determination on whether a standard has been violated. MRO also makes recommendations to PUB regarding the imposition

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[161] *See The Manitoba Hydro Act*, C.C.S.M. c.H190, s.16.3(1)(a), available at: http://web2.gov.mb.ca/laws/statutes/ccsm/h190e.php. The bracketed language above was stricken in *The Manitoba Hydro Amendment and Public Utilities Board Amendment Ac*t (dated June 11, 2009), and replaced with "an industry organization."

[162] Statutes of Manitoba 2009, c. 17.

[163] Available at: http://web2.gov.mb.ca/laws/regs/annual/2014/098.pdf.

of associated penalties or sanctions. The PUB will decide whether a violation of a standard has taken place and the penalty, if any, which should apply for noncompliance. The PUB can impose a penalty, with enforcement through a board order. When the PUB issues an order confirming a violation, NERC may make this fact and any attached penalties public.

NERC or MRO, in advising the PUB that they believe a violation has occurred, is also to advise on appropriate remedial actions, sanctions, or penalties.

Data Sharing

The compliance program requires timely data from registered entities to effectively monitor compliance with Reliability Standards.

All findings by PUB related to electricity reliability proceedings are made public through the issuance of orders. These orders will include the name of the registered entity, the Reliability Standard(s) and requirements(s) violated, whether the PUB agrees with MRO's findings and recommendations, and any penalties or sanctions imposed.

When the PUB issues an order confirming a violation, NERC may make this fact and any attached penalties public. The mitigation plan will not be made public until there is a confirmed violation. Similarly, final audit reports will be released to the public, but only after any alleged violations have become confirmed violations. Lastly, while compliance investigations are confidential, confirmed violations resulting from a compliance investigation will be made public.

New Brunswick

Reliability Standards

On October 3, 2008, NERC, the Minister of Energy of the Province of New Brunswick, and the New Brunswick System Operator (NBSO) signed a MOU that recognized NERC's role as the ERO and found that NERC is a "standards authority" within the meaning of the *New Brunswick Electricity Act*. NERC, NPCC, and NBSO have signed an MOU under which NERC and NPCC would monitor compliance and carry out enforcement as to NBSO. Under the MOU, NBSO was to monitor and enforce compliance with Reliability Standards by those entities within New Brunswick as a part of its market rules.

In October 2013, New Brunswick's legislation that amends how Reliability Standards are approved, monitored, and enforced received Royal Assent and was proclaimed (i.e., became effective). The *New Brunswick Electricity Act*[164] led to the amalgamation of NBSO with the NB Power Group of Companies. The system operation functions performed by NBSO are now performed within the vertically integrated New Brunswick Power Corporation (NBPC). In addition to its responsibility to comply with reliability standards applicable to its function, NBPC is also responsible for making filings to the New Brunswick Energy and Utilities Board (NBEUB) to update Reliability Standards, maintain a list of BPS elements, and to make recommendations on

[164] The *New Brunswick Electricity Act* is available at: http://laws.gnb.ca/en/ShowPdf/cs/2013-c.7.pdf.

compliance registrations. The NBSO's role in the adoption, monitoring, and enforcement of North American Reliability Standards has been transferred to the NBEUB.

The NBEUB may adopt FERC-approved NERC Reliability Standards that have been filed by NBPC. NERC Reliability Standards are filed and adopted with an accompanying NB Appendix to describe the specific application of the standard in New Brunswick. The NBEUB posts proposed Reliability Standards on its website for a 60-day review period prior to adoption. If the proposed Reliability Standard contains substantive revisions to the FERC-approved version, or if there are substantive comments received during the review period, the NBEUB may hold a hearing and may determine to approve, not approve, or remand the proposed Reliability Standard back to NBPC. A list of enforceable Reliability Standards is available on the NBEUB's website.[165]

Data Sharing

Confidentiality and public disclosure is governed by Part 7 of the *New Brunswick Compliance Monitoring and Enforcement Program* (NB CMEP) – Schedule A to the *Reliability Standards Regulation – Electricity Act*.[166] Any information that a registered entity provides to the NBEUB, NPCC, or NERC may be marked as confidential and may not be released to a third party without the written consent of the registered entity. The regulation provides for the public disclosure of finalized audit reports, confirmed violations, penalties, sanctions, and settlement agreements, including the name of the registered entity. The NBEUB is required to keep all CIP information confidential in accordance with §1500 of the NERC ROP.

Pursuant to the MOU, NERC provides information relevant to New Brunswick on issues relating to reliability, Reliability Standards, and compliance with Reliability Standards.

Compliance

The NBEUB implements a compliance monitoring system for reliability standards that is based on the requirements of the NERC compliance program. The NB program is documented as the NB CMEP – Schedule A to the *Reliability Standards Regulation – Electricity Act*. As a recognized compliance body under the regulations, NPCC assists the NBEUB with compliance monitoring activities according to a service agreement the NBEUB has executed with NPCC. The NBEUB will initiate enforcement action if it has reason to believe that a violation of a reliability standard has occurred. NBEUB requires that the entity take action to remove the risk the violation poses to the reliability of the BPS and to implement a plan that will prevent a future occurrence of the violation. Registered entities are subject to financial penalties and sanctions for violations of adopted reliability standards. A penalty matrix, provides ranges for penalties corresponding to VRFs and VSLs, is provided in the *Reliability Standards Regulation*.

[165] *See* http://www.nbeub.ca/index.php/en/electricity/reliability-compliance/118.

[166] New Brunswick's *Reliability Standards Regulation – Electricity Act* is available at: http://laws.gnb.ca/en/ShowPdF/cr/2013-66.pdf.

Nova Scotia

Reliability Standards

The Nova Scotia Utility and Review Board (NSUARB) is an independent, quasi-judicial body which exercises general supervision over all electric utilities operating as public utilities within the Province of Nova Scotia, pursuant to the *Nova Scotia Public Utilities Act*.[167] Nova Scotia Power Incorporated (NPSI) is a public utility in Nova Scotia and is a member of NERC and NPCC. The Nova Scotia Department of Energy is responsible for energy and electricity policy in the province.

NERC has signed two separate MOUs with entities in Nova Scotia: one with NSUARB, and one with NSPI.[168]

NERC submits standards to NSUARB and NSPI for approval; each organization may approve, modify, remand or dismiss the standard as not applicable, though final approval authority rests with NSUARB. NSUARB has a quarterly review process allowing the submission, by NERC, of standards already approved by FERC. NSUARB will only process an application after FERC has approved or remanded the Reliability Standard in the United States.[169] NERC made an initial filing of Reliability Standards on June 30, 2010 along with the *Glossary of Terms Used in NERC Reliability Standards*. Nova Scotia approved this filing on July 20, 2011. None of the proposed standards were changed or rejected.

On September 2, 2011, NERC made its first quarterly filing to Nova Scotia that included a list of Standards approved by FERC in the period of time since the June 30, 2011 filing. This filing was approved.

In June 2012, the NSUARB proposed an expedited process for its review of NERC quarterly filings. This was approved for implementation in August 2012. With respect to the quarterly filing, NSPI and NPCC have 10 days to comment if they wish. At the end of the comment period, the NSUARB will decide if, based on any comments, a more rigorous review is required. If a more rigorous review is deemed required it will be undertaken; otherwise, the NSUARB will issue its decision. To date, all filings have been approved without additional review.

Under the MOU with NPSI, NSPI agrees to comply with NERC's Reliability Standards. NPSI also committed to review and provide recommendations on the adoption of Reliability Standards.

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[167] The *Nova Scotia Public Utilities Act* is available at: http://nslegislature.ca/legc/statutes/public%20utilities.pdf.

[168] The NSUARB and NERC signed an MOU on December 22, 2006, in which NERC and the NSUARB agreed to a cooperative relationship to improve the reliability of the North American BPS. On May 11, 2010, NERC, NPCC, and NSPI signed an MOU which memorializes the working relationship between the three entities to improve reliability of the grid in Nova Scotia and North America. Both MOUs are available at: http://www.nerc.com/filingsorders/ca/pages/canadian-mous.aspx.

[169] The date of the order is considered the effective date for the adopted Reliability Standards.

Data Sharing

The MOU states that NSPI will provide NPCC all information respecting reporting requirements in the CMEP for NERC Reliability Standards.

Under the MOU, NERC has agreed to share relevant information on issues related to reliability compliance with the NSUARB. Examples of such information include:

(1) Compliance audits and spot checks;

(2) Readiness evaluations;

(3) Disturbance reports;

(4) Reliability assessments and benchmarking information; and

(5) Reports by regional reliability organizations, where applicable.[170]

There is also a data sharing requirement relevant to the Reliability Standards process. The MOU with NSUARB calls for NERC to submit all NERC Board of Trustees-approved Reliability Standards to the NSUARB. NERC also agreed to notify NSUARB immediately if a Reliability Standard has been remanded in another jurisdiction.

With respect to enforcement matters, the MOU states that the NSUARB and NERC will work together to establish a system for disclosure by NERC of violations to provide for assessment and reporting by NERC of inter-region reliability risks to or from entities outside of Nova Scotia where coordinated action is required to address those risks.

Compliance

Compliance is mandatory in Nova Scotia. NPCC as the regional Entity maintains the list of all market participants of the BES who must comply with approved reliability standards. NPCC provides recommendations to NSPI and may also identify organizations that may be candidates for registration and assign them to the compliance registry. The registry is based on the NERC functional model and registry criteria. The NSUARB will monitor compliance and accept compliance information and recommendations from NERC. NERC, NPCC and NSUARB may all suggest compliance violation; proceedings shall be conducted under the NSUARB's direction and control. NERC may recommend a particular penalty for any violation, but NSUARB will be responsible for determining if a violation occurred and what penalties should be imposed.

NSPI is subject to NERC's CMEP as implemented by NPCC.

[170] *See* MOU between the NSUARB and NERC at pp. 2-3.

Ontario

Reliability Standards

The Ontario Minister of Energy is responsible for the legislation that governs the Ontario Energy Board (OEB) and the Independent Electricity System Operator (IESO) and for energy and electricity policy in the province. The IESO of Ontario is a not-for-profit corporate entity established under the *[Ontario] Electricity Act, 1998*,[171] and is subject to the oversight authority of the OEB. The OEB is responsible for regulating the electricity sector, and it has the legislative authority to stay or revoke the operation of a reliability standard in Ontario and refer it back to NERC or NPCC for further consideration.

On October 25, 2006, the OEB and NERC signed an MOU[172] setting forth the mutual understanding of each party's responsibilities with respect to reliability in the Province of Ontario. The MOU states that Ontario's legislative framework does not expressly contemplate approval of NERC Reliability Standards, By-laws or Rules of Procedure. The MOU recognizes that, under the Ontario Electricity Act, one of the IESO's objectives is to participate in the development of standards relating to the transmission system and to enforce those standards. The MOU confirms that NERC Reliability Standards are referenced generically in the Market Rules written and administered by the IESO, and they are considered in effect in Ontario upon expiration of the remand period. On November 28, 2006, the Ontario Ministry of Energy formally recognized NERC as the entity named as a "standards authority" in the *Electricity Act, 1998*. Subsequently, in 2008, the *Electricity Act, 1998* was amended, allowing for NPCC to be recognized as a standards authority.

An MOU between the IESO, NPCC, and NERC was signed on November 29, 2006 and amended on February 5, 2010. This MOU documents the roles of the parties in conformance with the Ontario reliability framework and commits the IESO to carry out a compliance enforcement program for Ontario entities. The MOU also acknowledges that the NERC Rules of Procedure have effect in Ontario, provided they do not conflict with the established reliability and compliance framework in Ontario. The amended MOU includes provisions for investigations, organization registration, and NERC certification.[173] The IESO is subject to NERC's CMEP processes in accordance with the MOU. Monitoring and enforcement activities, with the exception of financial sanctions, are performed by NPCC.

While there continues to be no formal approval of NERC Reliability Standards in Ontario, there is a process for a Reliability Standard to be rejected or remanded. This process provides for market participants, the IESO, or the OEB itself to initiate a review that could result in a standard

[171] Ontario's *Electricity Act, 1998* is available at: http://www.e-laws.gov.on.ca/html/statutes/english/elaws_statutes_98e15_e.htm.

[172] Both the 2006 MOU and the 2010 MOU described in the following paragraph are available at: http://www.nerc.com/filingsorders/ca/pages/canadian-mous.aspx.

[173] In general, such NERC compliance processes do not involve direct participation by Ontario market participants.

being remanded or revoked for application in the province. Only Reliability Standards approved by the NERC Board of Trustees on or after May 14, 2008 are subject to this process.

Ontario was the first jurisdiction in North America to adopt NERC Reliability Standards as mandatory and enforceable. Until July 2011, a NERC Reliability Standard became effective on the date specified by the NERC Board of Trustees when it approved the standard. Because of the uncertainties in the timing of FERC approvals, a standard typically came into effect earlier in Ontario than in adjoining U.S. jurisdictions. An Ontario Market Rule amendment effective July 8, 2011 addressed this mismatch. Under this Market Rule,[174] a NERC Reliability Standard will become effective when it is declared mandatory and enforceable in the U.S., unless the OEB remands the Reliability Standard or otherwise stays its enforceability. In addition, any Reliability Standard approved by the NERC Board of Trustees under NERC Rule 321 (i.e., a standard responsive to a regulatory directive that has not been approved by the NERC RBB) must be approved by IESO before it can comes into effect in Ontario.

To date, Ontario has neither remanded nor modified any NERC Reliability Standards. Information regarding Reliability Standards in Ontario can be found on the IESO's website.[175]

Data Sharing

Under the MOU, NERC will provide the OEB with information relevant to Ontario on issues related to compliance with NERC Reliability Standards, including reports on:

(1) Compliance audits and spot checks;

(2) Readiness audits;

(3) Disturbance reports;

(4) Reliability assessments and benchmarking information; and

(5) Reports by regional reliability organizations, where applicable.

The MOU also calls for NERC to inform the OEB of Reliability Standards approved by NERC and submitted to appropriate regulatory authorities, and to notify the OEB of NERC Reliability Standards that are remanded to NERC in any jurisdiction outside of Ontario. The MOU states that the IESO is the only Ontario entity directly accountable to NERC for its own compliance and will be accountable to NERC for compliance by all Ontario entities with NERC Reliability Standards.

In the MOU, there is also an undertaking that, subject to confidentiality requirements, the IESO will advise NERC of the functional responsibilities of Ontario entities.

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[174] *See Market Rules for the Ontario Electricity Market*, ch. 5, Bulk Power System Reliability, available at: http://ieso-public.sharepoint.com/Documents/marketRules/mr_marketRules.pdf.

[175] *See* https://www.ieso.ca/imoweb/ircp/reliabilityStandards.asp.

Compliance

The IESO is subject to NERC's CMEP, with the exception that the IESO is not subject to financial sanctions.

Compliance enforcement within Ontario, i.e., of Ontario market participants, is conducted by the IESO's Market Assessment and Compliance Division, which is "ring-fenced" from the rest of the organization. The IESO is subject to assessments of compliance with NERC Reliability Standards, including audits performed by NPCC. The MOU provides NPCC and NERC the right to draw their own conclusions with respect to a compliance investigation of Ontario entities, but with limited authority to impose financial sanctions on the IESO only.

The IESO carries out a compliance enforcement program and can issue a monetary order, finding, or remedial action with respect to a violation of a Reliability Standard in Ontario, subject to appeal to the OEB. The IESO has delegated enforcement accountability to the Market Assessment and Compliance Division, which exercises independent discretion in terms of enforcement decision-making.

The Market Assessment and Compliance Division establishes and executes procedures and programs for monitoring, investigating, and imposing sanctions, including financial penalties, against market participants and the IESO itself. The MOU acknowledges the Market Assessment and Compliance Division as the enforcement body in Ontario for Reliability Standards with full sanctioning powers as afforded under the Market Rules for breaches committed by the IESO and Ontario market participants.

In the event that a violation is confirmed under the Market Rules, the name of the responsible entity is made public. The Market Assessment and Compliance Division has the authority to levy sanctions for reliability violations. These sanctions may include financial penalties and are subject to appeal to the OEB. The Market Assessment and Compliance Division has established sanctions guidelines similar to those of NERC using severity/impact criteria. It has authority for "Extraordinary Financial Penalties" under certain circumstances to assess penalties of up to $1 million per occurrence. The OEB can impose administrative penalties of up to $20,000 per day.

Québec

Reliability Standards

The Régie de l'énergie du Québec (Régie) is an independent agency established under the *Act Respecting the Régie de L'Énergie* (Régie Act) to regulate the province's electricity and natural gas sectors. On December 8, 2006, NERC and the Régie signed an MOU that contemplated a future amendment to Québec's reliability legislation to grant the Régie the power to adopt and enforce NERC standards and allow for NERC funding and oversight in the province of Québec.[176]

[176] NERC-Canadian MOUs are available at: http://www.nerc.com/filingsorders/ca/pages/canadian-mous.aspx.

The MOU noted that §73.1 of the Régie Act provides that the "electric power carrier," or Hydro-Québec, will establish reliability standards for its electric power transmission system and submit them to the Régie for approval. According to the MOU, the standards will become mandatory after approval by the Régie.

On December 13, 2006, Québec implemented *An Act Respecting the Implementation of the Québec Energy Strategy and Amending Various Legislative Provisions*,[177] which grants the Régie jurisdiction over a mandatory reliability standards framework in the Province of Québec. This act formalizes the ability of the Régie to approve reliability standards after reviewing an evaluation of the relevance and impact of the proposed standards. Under the act, the Régie may request that the Reliability Coordinator modify a standard or submit a new one. Further, the Reliability Coordinator must submit guidelines to the Régie describing criteria to be taken into account in determining sanctions for noncompliance with reliability standards and identify owners or operators that will be subject to the standards approved by the Régie.

On June 2, 2009, the RC filed an application seeking the adoption of 95 NERC Reliability Standards applicable in Québec, in French and English, along with an evaluation of the relevance and impacts of standards filed with the Régie. The filing also called for the approval of Registers of Entities and of Facilities, and approval of a *Glossary of Terms Used in NERC Reliability Standards*, among other things. The entities' and facilities' registers, as filed for approval, also provide interpretations regarding standard applications within Québec, and among other matters, a BES definition for the Québec Interconnection that is more stringent than NPCC's BPS definition.

In a partial decision issued on May 13, 2011, the Régie approved the content of the submitted NERC Reliability Standards.[178] In addition, the Régie accepted the Main Transmission System to be the system that defines the transmission and generation facilities to which Reliability Standards are applicable (TO, GO, GOP, TOP). The partial decision also called for a number of changes in how the standards and appendices are presented and for a review of the translation of the standards into French. The Régie is working to ensure the French version of the standards is as close in meaning to the English version as possible. The Régie will establish a timetable for filing of revised versions of the standards in English and French for final adoption. Accordingly, no NERC Reliability Standards have been formally adopted nor made effective in Québec.

The second agreement among NERC, the Régie, and NPCC regarding implementation of mandatory Reliability Standards in Québec has been developed, and the agreement is under consideration by the Québec provincial government. The Régie has issued a decision to adopt a second group of Reliability Standards for Québec, which brings the total number of adopted standards in Québec to 35. Following public hearings which took place in October 2013, it is expected that the Régie will issue a decision concerning a third group of standards. Hydro-Québec

[177] Available at: http://www2.publicationsduquebec.gouv.qc.ca/dynamicSearch/telecharge.php?type=5&file=2006C46A.PDF.

[178] A list of these approved Reliability Standards is available at: http://www.regie-energie.qc.ca/audiences/3699-09/Demande_3699-09/B-1_HQCME-2Doc1_3699_02juin09.pdf.

TransÉnergie, the Québec RC, has initiated a consultation process on 18 NERC Reliability Standards that will be filed with the Régie once its decision on the third group of standards is issued. This filing is expected before the end of 2014. The review of the Sanction Guide proposed by Hydro-Québec TransÉnergie and the determination of Reliability Standards enforcement dates remains pending.

Data Sharing

Under the MOU, NERC has agreed to share relevant information on issues related to reliability compliance with the Régie. The MOU further states NERC will be invited to participate in compliance audits and readiness evaluations done in Québec. Under the MOU, NERC and the Régie also agreed to discuss issues relating to: (i) Reliability Standard approval and remand; (ii) penalties for noncompliance with standards; and (iii) funding. For instance, NERC has agreed to notify the Régie when a new or modified standard is approved in the U.S. or remanded by any other jurisdiction outside of Québec. Additionally, although it is recognized that NERC cannot impose financial penalties for violations of Reliability Standards in Québec, NERC has agreed to inform the Régie of any violations and of the corresponding amount of penalties associated with such a violation in the United States.

Compliance

The Régie is responsible for compliance and enforcement. If NERC or NPCC determines that an entity subject to a Reliability Standard is not in compliance with the Reliability Standard, it shall report to the Régie on its findings and may recommend the application of a sanction. Ultimately, the Régie will determine if there has been a violation and will determine any appropriate penalty.

The RC must submit guidelines to the Régie describing criteria to be taken into account in determining sanctions for noncompliance with Reliability Standards and identify owners or operators that will be subject to the standards approved by the Régie. The intent, once all agreements are in place, is that NPCC and NERC will act as the Régie's agents in developing and delivering a comprehensive CMEP, subject to the approval of the Régie. As the first limited list of mandatory standards have only recently come into effect, and as the governmental authorities have not approved the agreement covering compliance arrangements, there has been limited compliance activity under the formal Québec regime.

The agreements note that NERC cannot impose financial penalties, but should recommend to the Régie what would be an appropriate sanction for a particular violation. The RC did submit a sanctions guide to the Régie as required. However, the regulator decided to postpone considering this until the second agreement covering compliance monitoring is approved by the governmental authorities. Under the provincial regime, the Régie may impose, if appropriate, a sanction that may not exceed $500,000 per day and set a deadline for payment.

Saskatchewan

Reliability Standards

Pursuant to *The Power Corporation Act*,[179] Saskatchewan Power Corporation (SaskPower) has the authority to adopt, set, and administer standards for the planning, design, or operation of transmission lines, equipment, or other facilities within the Saskatchewan integrated regional power grid, and to maintain a membership in an integrated regional power organization. NERC, MRO, and SaskPower entered into an MOU that became effective on February 3, 2009 and was amended on January 15, 2012.[180] The MOU reflects the intent of Saskatchewan to support common North American BPS standards and to describe the protocols to achieve such a goal. For purposes of the MOU, NERC, and MRO are recognized to be Saskatchewan's electric Reliability Standard setting bodies.

Reliability Standards approved by the NERC Board of Trustees are automatically adopted in Saskatchewan, unless one of the following two conditions applies. First, if a particular standard has been remanded by any jurisdiction, the Reliability Standard will not be applicable in Saskatchewan. Second, a Reliability Standard will not be applicable in Saskatchewan if is remanded, set aside, or a variance has been requested. Under the MOU, once the Reliability Standard is adopted, compliance with the standard is required in Saskatchewan.

Data Sharing

The MOU between MRO, SaskPower, and NERC does not have an explicit provision regarding public disclosure of violations.

Compliance

Under SaskPower's legislative authority, the oversight unit within SaskPower serves as the monitoring, compliance, and enforcement authority for the province. MRO currently performs on-site compliance audits for SaskPower. While not delegating its reliability authority, SaskPower aligns its compliance program, to the degree reasonable, to the compliance and monitoring processes established by NERC and MRO.

The process includes, but is not limited to, the following three functions:

(1) Oversight (including remand, set aside, and compliance findings);

(2) Standards development (including the coordination of assessments, communication, and internal education); and

[179] Available at: http://www.qp.gov.sk.ca/documents/English/Statutes/Statutes/P19.pdf.

[180] NERC-Canadian MOUs are available at: http://www.nerc.com/filingsorders/ca/pages/canadian-mous.aspx.

(3) Compliance and enforcement (including management of an internal and external auditing function, which will give Saskatchewan the ability to make formal findings of compliance and noncompliance and to order and enforce mitigation plans to be implemented).

The oversight unit within SaskPower would make any determination of a violation. There is no provision for financial or other sanction. The oversight unit can impose a mitigation plan on a noncompliant entity.

National Energy Board

Reliability Standards

NERC and the NEB signed an MOU in 2006. The MOU recognizes NERC as the ERO. In the MOU, NERC and the NEB commit to coordinate in the promotion of a reliable North American BPS.

The NEB regulates the construction and operation of international power lines in accordance with, among other things, the *National Energy Board Act* and the *National Energy Board Electricity Regulations*.[181] The NEB has authority under its legislative framework to take certain enforcement measures in the case of noncompliance to the conditions of a permit or a certificate that was issued for an international power line.

While initially the NEB did not have an authority to make Reliability Standards mandatory and enforceable on international power lines, this was changed with the passage of NEB's *General Order MO-036-2012 for Electricity Reliability Standards* and five amending orders for Electricity Reliability Standards in December 2012 (NEB General Order).[182]

The provisions of the NEB General Order contain twelve Reliability Standards requirements that correspond to the main categories of Reliability Standards developed by NERC. The requirements are defined broadly so that they may include regional variations and can be harmonized with provincial regulatory frameworks as they relate to Reliability Standards.

In the NEB General Order, the NEB did not itself adopt any NERC Reliability Standards. Rather, the NEB General Order requires that international power line owners file with the NEB a list of Reliability Standards adopted by the provincial system to which the international power line connects. The NEB General Order requires international power line owners or permit holders to identify these Reliability Standards and to keep the NEB advised of any changes. Accordingly, there is no list of the NEB-approved Reliability Standards, nor does the NEB make determinations of effective dates. The NEB also committed to working with the provinces, utilities and other reliability authorities including NERC to avoid, to the extent possible, the generation of duplicate

[181] NEB maintains a list of acts and regulations that set forth its mandate, responsibilities, and powers at: http://www.neb-one.gc.ca/clf-nsi/rpblctn/ctsndrgltn/lstctsndrgltn-eng.html.

[182] The NEB General Order is available at: http://www.neb-one.gc.ca/clf-nsi/rpblctn/ctsndrgltn/rrggnmgpnb/lctrcty/lctrcty-eng.html.

reporting requirements. However, international power line owners are required to submit to the NEB reports of noncompliance with Reliability Standards.

Data Sharing

NERC and the NEB have committed to exchange of experience, information and data relating to the development and compliance with Reliability Standards as applicable to international power lines. The MOU commits NERC to informing and seeking input from the NEB on proposed changes to NERC's Bylaws or ROP. The MOU also commits NERC to inform the NEB when a SAR has been approved and assigned to a drafting team, and to notify NEB when a Reliability Standard is approved.

Under the MOU, NERC commits to notify the NEB at the stage of its development process where the Standards Committee approves a SAR and assigns it for development by a drafting team. The NEB agrees to inform NERC about any changes in its regulatory processes to allow formal approval of NERC Reliability Standards.

Compliance

Consistent with its approach to adopting standards, the NEB has not imposed its own additional compliance monitoring and enforcement regime. The NEB General Order requires international power line permit holders to provide the NEB with certain compliance information, based on the compliance program of the jurisdiction where the international power line is located. In 2012, legislation was passed to provide the NEB with authority to establish a system of Administrative Monetary Penalties (AMP) through regulations in order to promote compliance with the *National Energy Board Act*. The penalties can be up to $100,000 per day for violations levied on companies. Lesser amounts can be levied on individuals. The NEB's regulations on how the AMP would be applied came into force in mid-2013.

There currently is no specific provision that violations would be made public.

Mexico

Baja California

Reliability Standards

The Comisión Federal de Electricidad (CFE), through the Centro Nacional de Control de Energia (CENACE), and the Area de Control Baja California (ACBC) have entered into a MOA with WECC. The MOA provides that WECC assist CENACE and ACBC in monitoring compliance with Mexico Reliability Standards for Baja California, Mexico. CENACE has approved the following Mexico Reliability Standards:

- BAL-001-MX-0 (Real Power Balancing Control Performance)
- BAL-006-MX-0 (Inadvertent Interchange)

- CIP-001-MX-0 (Sabotage Reporting)
- INT-001-MX-0 (Interchange Information)
- INT-003-MX-0 (Interchange Transaction Implementation)
- PER-001-MX-0 (Operating Personnel Responsibility and Authority)
- PER-002-MX-0 (Operating Personnel Training)
- PER-003-MX-0 (Operating Personnel Credentials)
- VAR-002-WECC-MX-0 (Automatic Voltage Regulators (AVR))
- VAR-501-WECC-MX-0 (Power System Stabilizer (PSS))

CFE participates in the NERC Reliability Standards and WECC regional standards development process to develop standards.

Compliance

WECC uses a compliance monitoring program[183] to monitor and assess compliance with Mexico Reliability Standards applicable to Designated Entities,[184] consistent with the applicable law of Mexico and relevant agreements. If there is any conflict between the MOA and the CMP, the MOA prevails.

WECC does not have enforcement or registration/designation authority for CFE. WECC provides compliance monitoring, reviews mitigation plans and completed mitigation plans, and provides assessment recommendations with respect to alleged violations.

[183] The 2014 implementation plan for Mexico Reliability Standards, together with other CFE-related documents and compliance information, is available at: http://www.wecc.biz/compliance/Baja_CFE/Pages/Baja-English.aspx.

[184] "Designated Entities" are the Mexican equivalent of registered entities in the United States.

FEDERAL ENERGY REGULATORY COMMISSION
DOCKET NO. RR14-___

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

ATTACHMENT 2

TO

FIVE-YEAR ELECTRIC RELIABILITY ORGANIZATION PERFORMANCE ASSESSMENT REPORT

JOINT REGIONAL ENTITY SELF-ASSESSMENT

JULY 21, 2014

Attachment 2

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Appendix A: Description of Regional Entities

Appendix B: Regional Entity Responses to Specific Concerns Raised in the Commission's September 16, 2010 Order on the Three-Year ERO Performance Assessment

Appendix C: Regional Entities' Satisfaction of Statutory and Regulatory Criteria

INTRODUCTION

The Regional Entities are pleased to have the opportunity to submit jointly a self-assessment of their performance for 2009 through 2013, to the Federal Energy Regulatory Commission (Commission or FERC), as part of the *Five-Year Electric Reliability Organization (ERO) Performance Assessment Report* prepared by the North American Electric Reliability Corporation (NERC).[1] While their corporate structures may vary, the Regional Entities are uniformly committed to working together and with the ERO to ensure the reliability of the bulk power system (BPS) in the U.S., and, where applicable, in Canada and Mexico. They are likewise dedicated to create seamless implementation of the law and policies administered by the Commission and the ERO. In light of the commonality of these overarching objectives, under the leadership of the Regional Entity Management Group (REMG), the Regional Entities prepared this 2014 Joint Regional Entity Self-Assessment (JRESA), which they respectfully request that the Commission accept.

The main purpose of this self-assessment is to demonstrate that the Regional Entities continued during the assessment period to satisfy the statutory and regulatory criteria for certification as part of the ERO. In this regard, in its order accepting the ERO's Three-Year Performance Assessment, the Commission explicitly directed that future assessments of the Regional Entities include a separate section assessing each Regional Entity's satisfaction of those criteria.[2] This self-assessment also provides an update on issues and concerns raised in the 2009 JRESA, specifically with respect to regional Reliability Standards, organization registration and certification, the compliance monitoring and enforcement program, and additional statutory functions.[3]

A. Satisfaction of Statutory and Regulatory Criteria

Section 215(e)(4) of the Federal Power Act (FPA), 16 U.S.C. §824o(e)(4), as reiterated in §39.8 of the Commission's regulations, 18 C.F.R. §39.8 (2013), provides that a Regional Entity must satisfy the following criteria to be delegated "authority for the purpose of proposing reliability standards to the ERO and enforcing reliability standards:"

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[1] The eight Regional Entities are: (i) Florida Reliability Coordinating Council, Inc. (FRCC); (ii) Midwest Reliability Organization (MRO); (iii) Northeast Power Coordinating Council, Inc. (NPCC); (iv) ReliabilityFirst Corporation (ReliabilityFirst or RF); (v) SERC Reliability Corporation (SERC); (vi) Southwest Power Pool Regional Entity (SPP RE) — an independent and functionally separate division of Southwest Power Pool, Inc. (SPP); (vii) Texas Reliability Entity, Inc. (Texas RE or TRE); (viii) and Western Electricity Coordinating Council (WECC). A description of each of the individual Regional Entities can be found at Appendix A.

[2] *See North American Electric Reliability Corporation*, Order on the Electric Reliability Organization's Three-Year Performance Assessment, 132 FERC ¶ 61,217 (2010), at P 36. The Commission also discussed specific concerns regarding each of the individual Regional Entities in the order on the three year assessment. *Id*. PP 198-244. The responses of the individual Regional Entities to those concerns can be found at Appendix B.

[3] The instant self-assessment will not repeat the discussion on the framework of self-regulation and delegation, found at pp. 12-18 of the 2009 JRESA, as that discussion was more appropriate for an assessment of the initiation of the reliability paradigm; however, opportunities to improve that structure are discussed *infra* pp. 6-8.

(1) The Regional Entity is governed by an independent board, a balanced stakeholder board or a combination independent and balanced stakeholder board.

(2) The Regional Entity meets the requirements otherwise applicable to the ERO in FPA §215(c)(1)(2), 16 U.S.C. §824o(c)(1)(2), namely that it (a) has the ability to develop and enforce reliability standards that provide for an adequate level of reliability of the bulk-power system; and (b) has established rules that (i) assure its independence of the users and owners and operators of the bulk-power system, while assuring fair stakeholder representation in the selection of its directors and balanced decision-making in any ERO committee or subordinate organization structure, (ii) allocate equitably reasonable dues, fees, and other charges among end users for all activities, (iii) provide fair and impartial procedures for enforcement of reliability standards through the imposition of penalties, (iv) provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing reliability standards and otherwise exercising its duties, and (v) provide for taking appropriate steps to gain recognition in Canada and Mexico.

(3) The Regional Entity operates under a delegation agreement that promotes effective and efficient administration of bulk-power system reliability.

Each of the eight Regional Entities continued to satisfy the statutory and regulatory criteria during the assessment period, as demonstrated with specificity on Appendix C and summarized briefly here.

The Regional Entities met the first criterion by being governed by an independent board (SPP RE and WECC (as of January 1, 2014)), a balanced stakeholder board (FRCC and SERC), or a combination independent and balanced stakeholder board (MRO (as of January 1, 2013), NPCC, RF, TRE, and WECC (during the assessment period)).

The Regional Entities fulfilled the next requirement to develop and enforce Reliability Standards that provide an adequate level of reliability of the BPS by working closely with NERC and stakeholders in the development of continent-wide standards and in the implementation and improvement of the Compliance Monitoring and Enforcement Program (CMEP). In particular, although each Regional Entity had a regional Reliability Standards Development Procedure (RRSDP), with the exception of WECC, they developed few regional Reliability Standards during the assessment period. They preferred to support NERC's efforts to develop continent-wide standards and focus their resources primarily on monitoring compliance with, and enforcement of, the mandatory Reliability Standards. Illustratively, during the assessment period, the Regional Entities conducted 2,358 compliance audits and 1,612 compliance spot checks, and processed 4,740 self-reports. They discovered nearly 6,900 violations or possible violations of the mandatory Reliability Standards, and submitted through NERC 5,128 confirmed violations in 633 Notices of Penalty (NOPs) to the Commission. They also explored ways to approach their compliance and enforcement responsibilities with a greater emphasis on

measuring the risk of noncompliance on the reliability of the BPS. In this regard, in collaboration with NERC, they developed the Reliability Assurance Initiative (RAI).[4]

The Regional Entities also established rules to ensure impartiality in the conduct of their business and due process in the performance of their compliance and enforcement functions, and, where applicable, took the appropriate steps to gain recognition in and otherwise work with entities in Canada and Mexico. To start with, they followed the NERC Rules of Procedure (ROP), as approved by the Commission, and adopted additional procedures and policies for their own areas. Thus, for example, they all relied on NERC ROP *Sanction Guidelines*, Appendix 4B, CMEP, Appendix 4C, and *Hearing Procedures,* Attachment 2 to Appendix 4C to carry out their compliance, enforcement, and hearing responsibilities fairly and impartially. They augmented those rules with policies and procedures to prevent conflicts of interest in the operation of their boards of directors or trustees, the exercise of their statutory duties, and the activities of their employees and contractors. They also followed NERC's lead, again as approved by the Commission, in equitably recovering their funding from end users through a formula based on net energy for load (NEL), and developed annual business plans and budgets for Commission approval to assure that they properly and adequately accounted for those funds. As noted, while they generally forwent the development of regional Reliability Standards during the assessment period, the Regional Entities participated in the development and improvement of the NERC Reliability Standards while maintaining their RRSDPs in the event they were needed. Finally, three of the Regional Entities with international footprints—MRO, NPCC, and WECC—made appropriate arrangements with Canadian border provincial authorities and utilities to coordinate the oversight of Canadian and U.S. reliability efforts, and WECC entered into a memorandum of understanding with the Mexican energy regulator under which WECC acts as a compliance monitor for certain activities in Baja California, Mexico.

Finally, the Regional Entities satisfied the statutory and regulatory criterion for maintaining their delegated authority by operating under agreements with NERC that promoted effective and efficient administration of BPS reliability. As described by the Commission when it first approved NERC's delegation agreements with the Regional Entities (RDAs) in 2007, NERC delegated authority under those agreements to the Regional Entities to audit, investigate, and otherwise ensure that users, owners, and operators of the BPS comply with NERC's mandatory Reliability Standards, subject to ERO oversight.[5] The RDAs further addressed regional Reliability Standards development, registration of entities that must comply with Reliability Standards, and other services supporting NERC's functions, including reliability assessments, event analysis, and training and education. In October 2010, the Commission again approved (revised) RDAs between NERC and each of the eight Regional Entities.[6]

[4] Regional activity and actions in regard to standards development and the CMEP, in particular RAI, are discussed later in greater detail under those headings.

[5] *See North American Electric Reliability Corp.*, 119 FERC ¶ 61,060, *order on reh'g,* 120 FERC ¶ 61,260 (2007).

[6] *See North American Electric Reliability Corporation*, 133 FERC ¶ 61,061 (2010), *order on reh'g*, 134 FERC ¶ 61,179, *order on compliance filing*, 137 FERC ¶ 61,028 (2011).

Subsequently, the Commission also approved other changes to specific regional agreements.[7] In brief, the Regional Entities functioned during the assessment period under RDAs with NERC that were comprehensively reviewed and ultimately approved by the Commission to promote effective and efficient administration of BPS reliability.

As a separate but related matter, each of the Regional Entities underwent at least one extensive audit by the Commission staff during the assessment period. Most of these audits evaluated the Regional Entities' budget formulation, administration, and execution, and focused on the costs and resources used to achieve program objectives in fulfilling the duties delegated to them by the ERO under FPA §215.[8] The final audit reports concluded that the Regional Entities had policies, procedures, and controls that facilitated their carrying out, in an effective and efficient manner, their responsibilities under their RDAs and bylaws, as well as their budget obligations. Several other audits more closely examined the structures of the regional organizations, and made recommendations in particular with respect to separation of functions.[9] In all of these proceedings, during the assessment period, the Regional Entities completed or were in the process of completing the corrective actions suggested by the Commission or its staff. The Regional Entities believe that the overall conclusions and recommendations in the Regional Entity audits underscore that they satisfied the statutory and regulatory criteria for maintaining the authority delegated to them by the ERO.[10]

B. Achievements

Closely intertwined in the Regional Entities' satisfaction of the statutory and regulatory certification criteria during the assessment period were their achievements as individual organizations and as a group united by common goals. Their individual achievements are partly set forth in Appendix C, and discussed or referenced throughout this document. Their joint achievements are, by definition, likewise discussed throughout this document. These achievements in particular reflect the work and oversight of the REMG, an organization composed of the executives of the eight Regional Entities to provide strategic guidance in the execution of their RDAs, consistent with maintaining and enhancing reliability across North

[7] *See*, e.g. *North American Electric Reliability Corporation*, Docket Nos. RR13-7-000 (Aug. 19, 2013) (TRE), RR13-5-000 (June 12, 2013) (MRO), RR12-12-000 (Oct. 24, 2012) (RF), RR12-4-000 (June 12, 2012) (FRCC), and RR12-2-000 (March 1, 2012) (WECC) (unpublished delegated letter orders).

[8] *See* delegated letter orders and final audit reports issued in *North American Electric Reliability Corporation*, Docket Nos. FA12-14-000 (May 9, 2013) (MRO), FA12-7-000 (May 9, 2013) (RF), PA12-10-000 (June 28, 2013) (NPCC), FA12-6-000 (June 11, 2013) (SERC), PA11-2-000 (October 5, 2011) (SPP RE), and PA12-9-000 (July 10, 2013) (WECC) (unpublished delegated letter orders).

[9] *See Florida Reliability Coordinating Council, Inc*., 131 FERC ¶ 61,262 (2010); *Western Electricity Coordination Council*, 132 FERC ¶ 61,149 (2010); *Texas Regional Entity*, 130 FERC ¶ 61,025 (2010).

[10] NERC also audited the Regional Entities during the assessment period, in accordance with the Commission's direction in Order No. 672. *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204 (2006), at P 773. Specifically, NERC developed a program to audit the Regional Entities' adherence to the NERC ROP, the CMEP, and the requirements of the Regional Delegation Agreements. *See* generally http://www.nerc.com/pa/comp/Audits%20of%20Regional%20Entities%20DL/Forms/AllItems.aspx.

America for the benefit of all BPS users, owners, and operators. The REMG aims to attain that objective by promoting information sharing, transparency, and consistency with and among the Regional Entities while assuring efficient and effective use of resources to execute their delegated functions. In addition, the REMG combines the Regional Entities' efforts with the ERO Executive Management Group (ERO EMG), which was chartered originally in April 2010, and likewise dedicated to provide guidance and direction in the execution of the RDAs.

As particularly relevant to the rest of this self-assessment, in the summer of 2012, the REMG held its first strategic retreat, and decided upon three priorities: (i) to ensure that their work, especially in the audit area, follows professional standards and as a result fosters consistency among the Regional Entities; (ii) to reserve enforcement for serious matters, rather than using enforcement for every corrective action resulting from a violation; and (iii) to scale their work towards risk to reliability and move away from a prescriptive, mechanical approach. Soon after this retreat, as discussed in greater detail below, the Regional Entities took steps to make these priorities a reality. With NERC's participation, they engaged a third-party consulting firm to perform a review of the Regional Entities' auditing practices, to identify areas to improve consistency among the Regional Entities, and to increase the rigor in the conduct of their work. Within a relatively short time, by the end of the assessment period, NERC and the Regional Entities made substantial progress on implementing the consulting firm's major recommendations to develop a standardized audit process checklist, to publish an auditor handbook, and to create an audit training program around these tools. The Regional Entities also worked closely with NERC and the registered entities to pursue the related second and third priorities of reserving enforcement for serious matters and directing their compliance and enforcement efforts to identifying risk to the BPS. In this regard, they continued to examine ways to improve the timeliness and effectiveness of their CMEP processes, including improvements in self-reporting and enhancements to the Find, Fix, Track and Report (FFT) program, and prepared analyses and initiated pilot programs to find better ways to gauge the risk that registered entities posed to reliability, and to scale their monitoring and enforcement efforts accordingly. As a result, the Regional Entities believe that a solid foundation was laid during the assessment period to advance to the next phase of the ERO Enterprise's maturation as captured conceptually in RAI.[11]

C. Improvement Opportunities

Notwithstanding the solid foundation for the continued effective functioning of the ERO Enterprise, the Regional Entities, in tandem with NERC, are committed to exploring ways to improve their operations and their contribution to the reliability of the BPS. In this regard, they have identified certain elements essential to improved operations of the ERO Enterprise on which they plan to focus in the months ahead. Specifically, they plan to pursue: (i) clarifying and refining roles and responsibilities; (ii) coordinating strategic planning and operational decision-making; (iii) continuing to improve consistency; (iv) sharing tools and infrastructure for delegated functions; and (v) coordinating communications.

[11] Toward the end of the assessment period, the reliability community began to use the expression "ERO Enterprise" to represent the combined efforts of NERC and the Regional Entities.

The undertaking to clarify and refine roles and responsibilities is especially important to the Regional Entities as it is critical to the smooth operation of the self-regulated model. At its core, the ERO Enterprise must exercise effective and well-coordinated reliability oversight that mitigates reliability risks to the BPS. Accordingly, NERC and the Regional Entities have identified objectives on which they will concentrate to clarify and refine roles and responsibilities within the ERO Enterprise. For example, NERC will consider including in its review of Regional Entity business plans adequacy of resources and alignment of the plans for achieving delegated function objectives and outcomes described in the three-year plan. For their part, the Regional Entities will work in a coordinated fashion to support NERC in the development of comprehensive functional program designs and controls; adapt existing regional programs for delegated functions to conform to emerging program designs provided by NERC; and ensure Regional Entity staffs meet qualification and training requirements.

In addition, NERC and the Regional Entities will strive to better coordinate their strategic and business planning, e.g., by developing and maintaining a joint three-year strategic plan for the ERO Enterprise describing the goals and deliverables for statutory functions, a plan that should guide the development of each Regional Entity's annual business plans. Along the same lines, NERC and Regional Entities intend to develop and transparently report results based on a common set of performance measures focused on BPS reliability outcomes and effectiveness of the statutory programs. Furthermore, they hope to better coordinate operational decision-making within the ERO Enterprise.

Lastly, at this time, NERC and the Regional Entities plan to focus on better achieving consistency, sharing tools and infrastructure for delegated functions, and coordinating external and cross-ERO Enterprise communications. Specifically, with NERC leading, the ERO Enterprise will explore developing a core set of methods, practices, procedures, and tools to support unified implementation of the major statutory functions of NERC. The Regional Entities and NERC will also examine developing ERO Enterprise IT applications, where appropriate, to support common processes, to enhance the efficiency and effectiveness of Regional Entities' practices, to increase the consistency of the interface with registered entities, and to facilitate NERC's oversight function. Finally, all parties of the ERO Enterprise plan to continue the joint board coordination to ensure oversight and accountability of all elements of the enterprise, and to continue refining and expanding coordinated outreach to government entities in the U.S. and Canada, stakeholders, and media.

The Regional Entities believe that this coordinated effort with NERC to improve the self-regulation model will result in more clarity around the roles and responsibilities between them and among them which in turn will lead to better coordination of goals, more uniform work processes and tools, and performance measures across the enterprise, along with an understanding that all parties comprising the ERO Enterprise must be vested in each other's success. These improvements will also create higher levels of productivity, less duplication, and greater efficiency in the oversight and execution of statutory functions and mitigation of BPS reliability risks. The Regional Entities look forward to working with NERC and the stakeholders in their continual pursuit of opportunities to improve their operations that will promote the reliability of the nation's BPS.

D. Regional Reliability Standards

The 2009 JRESA provided a brief overview of the regional Reliability Standards process and scope, and reviewed what had been achieved to date.[12] The following provides an update on that overview and review and additional information on the Regional Entities' progress in developing regional Reliability Standards.

1. Regional Reliability Standards Processes

FPA §215(d), 16 U.S.C. §824o(d), requires the ERO to develop mandatory and enforceable Reliability Standards that are subject to Commission review and approval. Once approved, the Reliability Standards may be enforced by NERC, subject to Commission oversight, or by the Commission independently. A Regional Entity may also develop a Reliability Standard for Commission approval to be effective in that region only. In Order No. 672, the Commission stated that:

> As a general matter, we will accept the following two types of regional differences, provided they are otherwise just, reasonable, not unduly discriminatory or preferential and in the public interest, as required under the statute: (1) a regional difference that is more stringent than the continent-wide Reliability Standard, including a regional difference that addresses matters that the continent-wide Reliability Standard does not; and (2) a regional Reliability Standard that is necessitated by a physical difference in the Bulk-Power System.[13]

In addition, FPA §215(d)(3), 16 U.S.C. §824o(d)(3), provides that the ERO "shall rebuttably presume that a proposal from a Regional Entity organized on an interconnection-wide basis for a reliability standard or modification to a reliability standard to be applicable on an interconnection-wide basis is just, reasonable, and not unduly discriminatory or preferential, and in the public interest."[14]

In October 2010, as noted earlier, the Commission approved revised RDAs between NERC and each of the eight Regional Entities.[15] As relevant here, Exhibit C to the revised RDAs includes each Regional Entity's current RRSDP.[16] These procedures provide the process that each Regional Entity uses to develop regional Reliability Standards that are proposed to NERC for adoption, and, where applicable, regional variances if the Regional Entity is organized

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[12] *See* 2009 JRESA, at pp. 19-20.

[13] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 291, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[14] *See also* 18 C.F.R. §39.5(b) (2013).

[15] *See North American Electric Reliability Corporation*, 133 FERC ¶ 61,061 (2010).

[16] *See* http://www.nerc.com/AboutNERC/Pages/Regional-Entity-Delegation-Agreements.aspx.

on an interconnect-wide basis. While the RRSDP's are not identical, each contains important common attributes that advance the development of regional Reliability Standards consistent with the objective of a uniform reliability program.[17] Illustratively, participation in the development of a regional Reliability Standard must be open to all organizations that are directly and materially affected by the Regional Entity's system, with no constraints based on financial capability, technical expertise or membership in the organization. The RRSDP must strive to have an appropriate balance of interests and may not be dominated by any two interest categories and no single interest category can defeat a matter. All entities with a direct and material interest in the BPS in the region may participate by expressing a position and its basis, having that position considered, and having the right to appeal. The RRSDP must also provide for reasonable notice and opportunity for public comment, and provide that all actions material to the development of any standards be transparent.[18] Under these circumstances, it can be fairly stated that during the assessment period, each of the Regional Entities fulfilled the obligation to provide an open, fair, balanced, and inclusive process for the development of regional Reliability Standards as demonstrated by the approval of those processes at the Commission, NERC, and regional levels.

NERC understandably focuses on the development of continent-wide standards as consistent with the goal of a reliable BPS, and, from the inception of the program, the Commission, NERC, and the Regional Entities anticipated that the Regional Entities would develop relatively few regional Reliability Standards to address unique situations with specific or more stringent requirements in a particular interconnection or geographic region which the continent-wide standards may not address. In fact, that has been proven to be the case. Since the Commission issued Order No. 693 in 2007, outside of WECC, the Commission has approved only seven regional Reliability Standards.[19] The regional Reliability Standards in effect as of the end of the assessment period are listed in Table 1.

[17] The Regional Entities regularly review their RRSDPs to ensure they are adequate to develop regional Reliability Standards consistent with Commission's directives and NERC's ROP *Standard Processes Manual* at Appendix 3A. *See,* e.g., *North American Electric Reliability Corporation*, Docket Nos. RR13-5-000 (June 12, 2013) (MRO), RR12-12-000 (Oct. 24, 2012) (RF), RR14-1-000 (Jan. 31, 2014) (SPP RE) , RR12-2-000 (March 1, 2012) (WECC) (unpublished delegated letter orders).

[18] In this regard, NERC maintains on its website a current overview of regional Reliability Standards under development, with detailed information on the status of the proceeding. *See* http://www.nerc.com/pa/Stand/Pages/RegionalReliabilityStandardsUnderDevelopment.aspx.

[19] WECC developed the most regional Reliability Standards because of a mandatory program it had in place prior to the approval of NERC as the ERO and the delegation to WECC. Under this program, called the Reliability Management System (RMS), WECC was required to translate existing reliability criteria into regional mandatory standards. *See,* e.g., *North American Electric Reliability Corporation*, 119 FERC ¶ 61,260 (2007) (describing the RMS and approving WECC-BAL-STD-002-0,WECC-IRO-STD-006-0, WECC-PRC-STD-001-1, WECC-PRC-STD-003-1, WECC-PRC-STD-005-1, WECC-TOP-STD-007-0,WECC-VAR-STD-002a-1,and WECC-VAR-STD-002b-1).

Regional Reliability Standards – Table 1	
Regional Entity	**Regional Reliability Standards (Description)** **FERC Docket Number, Citation**
FRCC	None
MRO	None
NPCC	**PRC-002-NPCC-01** (Disturbance Monitoring Equipment) RD11-8-000, 137 FERC ¶ 61,043 (2011). **PRC-006-NPCC-01** (Automatic Underfrequency Load Shedding) RM12-12-000, Order No. 775, 142 FERC ¶ 61,128 (2013).
RF	**BAL-502-RFC-02** (Planning Resource Adequacy Analysis, Assessment and Documentation) RM10-10-000, Order No. 747, 134 FERC ¶ 61,212 (2011).
SERC	**PRC-006-SERC-01** (Automatic Underfrequency Load Shedding Requirements) RM12-9-000, Order No. 772, 141 FERC ¶ 61,243 (2012).
SPP RE	None
TRE	**CIP-001-2a** (Regional Variance) (Cyber Security – Sabotage Reporting) RD11-6-000, Delegated Letter Order, August 2, 2011. **IRO-006-TRE-1** (Transmission Loading Relief) RD12-1-000, 139 FERC ¶ 61,169 (2012). **BAL-001-TRE-1** (Real Power Balancing Control) RD13-12-000, 146 FERC ¶ 61,025 (2014).
WECC	**FAC-501-WECC-1** (Transmission Maintenance) **VAR-002-WECC-1** (Automatic Voltage Regulators) **VAR-501-WECC-1** (Power System Stabilizer) **PRC-004-WECC-1** (Protection System and Remedial Action Scheme Misoperation) RM09-9-000, Order No. 751, 135 FERC ¶ 61,061 (2011). **IRO-006-WECC-1** (Qualified Transfer Path Unscheduled Flow Relief) RM09-19-000, Order No. 746, 134 FERC ¶ 61,199 (2011). **BAL-004-WECC-02** (Automatic Time Error Correction) (replacing BAL-004-WECC-1) RD13-11-000k, Delegated Letter Order (Oct. 16. 2013). **TOP-007-WECC-1** (System Operating Limits) RM09-14-000, Order No. 752, 135 FERC ¶ 61,062 (2011). **BAL-002-WECC-2** (Contingence Reserve) (replacing BAL-STD-002-2) RM13-13-000, Order No. 789, 145 FERC ¶ 61,141 (2013).

Indeed, while the Regional Entities believe that they should still have the authority to develop regional Reliability Standards under the conditions laid out by the Commission and

maintain their RRSDP's accordingly, with the exception of WECC, they are no longer actively engaged in developing regional standards.[20] Rather, they prefer to avoid duplicating NERC efforts, and concentrate their relevant resources on working with NERC and stakeholders to develop clear, reasonable, and technically sound continent-wide standards in a timely and efficient manner, and to ensure that regional concerns are addressed in the continent-wide standards. To this end, and as further discussed later under §D.3 below, Prioritization of Standards Work, the Regional Entities are actively encouraging awareness and participation in the NERC standards process by stakeholders in their areas, by educational outreach efforts, and through participation in the NERC Standards Committee and related subcommittees. They also have standards committees or groups that analyze the draft ERO standards to determine their quality and effectiveness, and to ensure the reliability objective is adequate and cost effective.

2. Regional Fill-in-the-Blank Standards and Regional Criteria

The 2009 JRESA agreed with stakeholders' concerns about the effect on reliability of the outstanding and incomplete "fill-in-the-blank" reliability standards projects.[21] During the assessment period, the ERO Enterprise made considerable progress to respond to the Commission's directives on those standards. This was accomplished in large part by greater collaboration and cooperation between NERC and the Regional Entities. Furthermore, the Regional Entities believe now that the appropriate resolution to the issue of fill-in-the-blank standards is the timely development of continent-wide NERC Reliability Standards.[22] Accordingly, as a general matter, the Regional Entities are no longer planning to develop Regional Reliability Standards to address the "fill-in-the blank" standards; however, they may pursue any unaddressed reliability gaps that new continent-wide standards may not cover.

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[20] Illustratively, during the assessment period, FRCC stayed work on four regional Reliability Standards (PRC-003-FRCC-01, PRC-002-FRCC-01, PRC-006-FRCC-01, and PRC-024-FRCC-01) in large part because of related activities at the national level. MRO developed four regional Reliability Standards, but found them unnecessary before even submitting them to the board. RF worked on a number of regional Reliability Standards (e.g., MOD-024-RFC-01, MOD-025-RFC-01, EOP-007-RFC-01, and PRC-002-RFC-01) that it subsequently, using its RRSDP, converted to Regional Criteria, which are essentially RF board-approved good utility practices. In August 2012, RF also suspended work on drafting efforts for PRC-006-RFC-01 and PRC-012-RFC-01. SPP RE developed one board-approved regional Reliability Standard (PRC-006-SPP-01), but withdrew the FERC filing in August 2013, because a continent-wide standard eliminated the need for it.

In contrast, WECC maintained and continued to develop regional Reliability Standards during the assessment period for two primary reasons: (i) the Western Interconnection has some unique characteristics and concerns; and (ii) several of the current WECC regional Reliability Standards projects are required by the initial FERC orders approving the WECC regional Reliability Standards as part of the transition from the RMS program. *See supra* note 19. *See* generally http://www.wecc.biz/Standards/Development/Pages/default.aspx.

[21] As explained in the 2009 JRESA, at p. 19, when the Commission approved 83 Reliability Standards in Order No. 693, it withheld a decision on certain standards that referred to Regional requirements that were not specifically noted within the standards. These were referred to as "fill-in-the-blank," meaning the entity had to refer to a Regional document for the answer of what level of performance was required.

[22] In this regard, for example, the Commission's approval of Reliability Standard PRC-006-1 addressed an area of significant concern with respect to under-frequency load shedding. *See Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards*, Order No. 763, 139 FERC ¶ 61,098 (2012).

3. Prioritization of Standards Work

While NERC is responsible in the first instance to develop the continent-wide standards, the Regional Entities clearly have a stake in that process, because they are ultimately responsible for enforcing compliance with those standards. Accordingly, during the assessment period, the Regional Entities supported NERC in response to the Commission's concerns to increase the efficiency and effectiveness of the standards development process and to improve the quality of the resulting Reliability Standards. As now discussed, the Regional Entities are encouraged by the advances that NERC made in this regard.

First, the Regional Entities support NERC's objective to transform the current set of Reliability Standards in 2014 through 2015 to high quality, technically sound, results-based, cost-effective standards, which collectively will help ensure the reliable operation of the North American BPS. They especially appreciate NERC's piloting of the Cost Effective Analysis Process (CEAP), which is intended to evaluate the cost effectiveness of standards under development.

Second, the Regional Entities appreciate NERC's development of the *Weekly Standards Bulletin*, which helps the registered entities and other stakeholders to keep apprised of standards development. Along the same lines, the Regional Entities believe that the quarterly *Analyses of NERC Standards Process Results* were also very helpful for a better understanding of, and provides insight to, the development of continent-wide standards.[23]

Third, the Regional Entities are encouraged by the Commission's approval of revisions to the NERC *Standard Processes Manual*, ROP Appendix 3A, finding that those revisions are reasonable and allow for greater flexibility and efficiency in the process.[24] The Commission highlighted that the revisions recognize the need for highly qualified standards drafting teams that include technical writers, legal and compliance resources, and rigorous and highly trained project management.[25] The Regional Entities, which are in daily contact with the stakeholders who must deal with the intricacies of compliance with the standards, agree that well-trained personnel are needed to ensure the quality and effectiveness of the mandatory Reliability Standards, and believe that NERC has made significant strides to achieve that objective.

Fourth, the Regional Entities are encouraged by NERC's response to the Commission's March 2012 invitation to suggest retirement of requirements within standards, and the Commission's approval of NERC's proposal to withdraw 34 requirements within 19 Reliability Standards, and the additional withdrawal of 41 Commission directives that NERC develop

[23] NERC submitted these analyses pursuant to FERC directives, including the order on the three-year assessment. *See Order on the Electric Reliability Organization's Three-Year Performance Assessment*, 132 FERC ¶ 61,217 (2010), at P 85.

[24] *See North American Electric Reliability Corporation*, 143 FERC ¶ 61,273 (2013), at P 18.

[25] *Id.*

modifications to Reliability Standards.[26] These actions signal a cooperative effort that will help alleviate some of the complexity and frustration that has plagued the development of standards for many years and ease compliance burdens on the registered entities. Along the same lines, the Regional Entities commend NERC's creation of the Standards Independent Experts Review project in 2012. During the assessment period, this group assessed the current non-Critical Infrastructure Protection (CIP) Reliability Standards to determine which requirements should be retired and to grade the remaining requirements for content and quality. More important, this group identified gaps where risks to reliability are not adequately addressed in the current set of standards, including outage coordination, governor frequency response, situational awareness models, and clear three-part communications.

Finally, the Regional Entities commend the NERC Board of Trustees (NERC Board) for forming the Reliability Issues Steering Committee (RISC) in August 2012. Through its efforts, RISC is helping to move the ERO Enterprise toward a more efficient standards development program and a sensible prioritization of the work to produce reasonable and effective standards and identify any emerging risks to reliability.

E. Organization Registration and Certification

The 2009 JRESA discussed the subject of compliance registry within the context of the CMEP.[27] While the topic fits there, it also lends itself to a separate discussion, as set out below.

1. Organization Registration

The Regional Entities and NERC are required to identify and register all entities that meet the criteria as laid out in the NERC ROP *Statement of Compliance Registry Criteria*, Appendix 5B.[28] The Regional Entities review and evaluate registration requests and changes and make registration recommendations to NERC when a request or change may affect the NERC Compliance Registry (NCR). NERC is responsible for registering those entities and establishing and maintaining the NCR of the BPS owners, operators, and users that are subject to approved Reliability Standards.[29]

As pointed out in the 2009 JRESA, the registration of BPS users, owners and operators has been a very successful aspect of the Regional Entities' obligation to monitor and enforce the

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[26] *See Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, Order No. 788, 145 FERC ¶ 61,147 (2013).

[27] *See* 2009 JRESA, at pp. 21-23. The 2009 JRESA used the term "Compliance Registry" whereas this section will use the current term "Organization Registration" and also discuss Organization Certification.

[28] *See* http://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/Appendix_5B_RegistrationCriteria_20140701_updated_20140602.pdf. *See* generally ROP §500, http://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/NERC_ROP_Effective_20140701_without_Appendices.pdf.

[29] *See* http://www.nerc.com/pa/comp/Pages/Registration-and-Certification.aspx.

Reliability Standards.[30] The Regional Entities believe that continued to be the case during the assessment period, as evidenced by the acceptance by the *vast* majority of the registered entities of their inclusion in the NCR. Indeed, as of December 31, 2013, relatively few registered entities, just 47 out of over 1,850 registered entities in the U.S., appealed their registrations by the Regional Entities to the NERC Board, and only nine of those appeals were filed after January 1, 2009.[31] The NERC Board upheld the Regional Entities' decisions, except in one case, and remanded aspects of another appeal directing the Regional Entity to consider whether two entities should be jointly registered.[32] And in two instances, the NERC Board simply asked the Regional Entity to supply more information on an entity's status.[33] Most important, as of December 31, 2013, only eleven registered entities appealed the NERC Board decisions upholding the Regional Entities' registrations to the Commission.[34]

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[30] *See* 2009 JRESA, at p. 21.

[31] The number "47" does not refer to the actual number of appeals. Twenty-two of the 47 registrants were involved in just eight appeals of FRCC registrations, five of which concerned the same types of county resource recovery facilities. (No appeal of an FRCC registration has been filed since January 1, 2009.) The other appeals to the NERC Board were filed regarding the registration decisions of MRO (1), RF (8), SERC (6), SPP RE (1), TRE (4), and WECC (5). *See* http://www.nerc.com/pa/comp/Pages/Decisions-on-Appeals.aspx.

[32] In NERC Docket RA080012, on January 16, 2013, the BOT remanded to SERC the issue of whether Louisiana Generating should be registered as a Distribution Provider. In NERC Docket RA080002, on August 19, 2008, the BOT remanded to RF an appeal of Cordova Energy Co, LLC, to consider whether Cordova and Constellation Energy Commodities Group, Inc. should be jointly registered.

[33] The NERC Board directed these requests to SERC regarding the U.S. Army Corps of Engineers-Ft. Worth District (in NERC Docket RA080011) and the North Carolina Electric Membership Corporation (in NERC Docket RA080007).

[34] The Commission denied four, granted six, and denied in part and granted in part one of those appeals.

See the following orders where the Commission denied registrants' appeals: *City of Holland, Michigan Board of Public Works*, 139 FERC ¶ 61,055 (2012), *order on reh'g*, 145 FERC ¶ 61,054 (2013 (denying appeal of RF's decision to register entity as a transmission owner and a transmission operator), *appeal pending sub. nom. City of Holland, Michigan Board of Public Works v. FERC*, No. 13-1306 (D.C. Cir. Dec. 16, 2013); *Cedar Creek Wind Energy, LLC and Milford Wind Corridor Phase I, LLC*, 135 FERC ¶ 61, 241 (2011), *order on reh'g*, 137 FERC ¶ 61,141 (2011), *order on compliance filing*, 139 FERC ¶ 61,214 (2012) (denying appeal of two entities of their registration by WECC as transmission owners and transmission operators); *Southeastern Power Administration*, 125 FERC ¶ 61,294 (2008) (affirming SERC's registration of SEPA as a transmission operator and resource planner).

See the following orders where the Commission granted registrants' appeals: *South Louisiana Electric Cooperative Association*, 144 FERC ¶ 61,050 (2013), *order on reh'g*, 145 FERC ¶ 61,232 (2013) (granting appeal of entity registered by SERC as a distribution provider and load-serving entity for lack of sufficient document); *Direct Energy Services, LLC, Sempra Energy Solutions LLC, and Strategic Energy, L.L.C*, 121 FERC ¶ 61,274 (2007), *order on compliance filing*, 123 FERC ¶ 61,016 (2008) (granting appeals of three entities which objected to their registration as load serving entities and directing NERC to submit a plan to address a possible gap in reliability because of inconsistent registration of certain types of entities); *Mosaic Fertilizer, LLC and City of Tampa, Florida*, 121 FERC ¶ 61,058 (2007) (remanding case to NERC for reconsideration of FRCC's registration or to provide further explanation for underlying decision).

See the following orders where the Commission denied in part and granted in part a registrant's appeal: *U.S. Department of Energy, Portsmouth/Paducah Project Office*, 139 FERC ¶ 61,054, *order on reh'g*, 141 FERC ¶ 61,108 (2012) (granting the appeal of DOE and finding that its Portsmouth facility should not be registered as a

While some individual registration cases were challenging, the organization registration program remained steady during the assessment period. The means by which new registered entities were discovered, for example, were similar to the original means, including self-registrations, compliance audits, public websites, independent system operator (ISO), and regional transmission organization (RTO) memberships (where relevant), information provided by other registered entities, exchange of information between Regional Entities (e.g., through the Regional Registration and Certification Functional Group), Energy Information Administration data, questionnaires, and, of course, word of mouth. The average time to process uncontested entity requests to register or de-register for a function (measured from the time the entity makes the request to the time the request is approved by NERC) likewise stayed the same, or even improved, during that period, taking as little time as three to five business days, or longer up to 90 days if complications arose, such as entity trying to change its registration during an audit. The greatest, albeit not that great, movement within the program was the changes in the number of functions (as opposed to entities) for which entities are registered, as reflected in Table 2.

Trends in the Activation and Deactivation of Functions – Table 2

Regional Entity	Registered Entities		Registered Functions		Trends in the Activation and Deactivation of Functions in the Regions during Assessment Period
	2009	2013	2009	2013	
FRCC	71	69	240	244	FRCC processed approximately 20 function activations, most of which were associated with changes to generating facility functional responsibilities such as a vendor accepting generator owner (GO) and generator operator (GOP) compliance responsibilities and new joint registration organizations (JROs); 14 function deactivations, most of which were associated with the same generation functional responsibility change and with distributor provider (DP) functional responsibilities being accepted by GO and TO; and 10 entity name changes.
MRO	118	134	435	453	MRO, which had registered 435 functions as of 1/1/09, had 453 registered functions at year-end 2013, for an increase of four percent.

load-serving entity on the basis of the evidence submitted) (Commissioner Norris dissenting); *U.S. Department of Energy, Portsmouth/Paducah Project Office*, 124 FERC ¶ 61,072 (2008) (affirming RF's registration of DOE facility as a transmission owner, transmission operator and distribution provider, but remanding to NERC the issue of whether it functions as a load-serving entity).

Trends in the Activation and Deactivation of Functions – Table 2					
Regional Entity	**Registered Entities**		**Registered Functions**		**Trends in the Activation and Deactivation of Functions in the Regions during Assessment Period**
	2009	**2013**	**2009**	**2013**	
NPCC	287	301	576	602	The number of registered entities in NPCC fluctuated slightly during the assessment period. At the end of the period, the number had risen to 301. The ultimate increase in the number of entities was due to the number of new GOs, GOPs, and purchasing-selling entities (PSEs) outpacing the delisting of GOs, GOPs, and PSEs.
RF	358	343	677	686	RF experienced very little change in the registration of new entities, and hence functions, during the assessment period. The majority of registry work involved name or ownership changes. A notable trend during the assessment period was the deactivation of GOs and GOPs that owned or operated blackstart resources. This deactivation may have occurred due to the compliance obligations and costs associated with owning and operating blackstart resources. RF is concerned by this trend, as it appears that the costs of compliance may be creating a perverse incentive for registered entities to dispose of blackstart resources, which are important to bulk electric system (BES) reliability.
SERC	227	244	643	694	SERC continued to see considerable change associated with PSE and GO/GOP functions, mostly due to changes in ownership or corporate structure. SERC also registered several new wind farms and a few new generating facilities. SERC's deactivations typically occurred when there was a change in ownership of an asset. Several BAs were deactivated in December 2013 as a result of integration into the MISO BA. Name changes occurred regularly. SERC anticipates most DPs/load serving entities (LSEs) connected via radial tie lines to request deactivation following the BES definition revisions and FERC's South Louisiana Electric Cooperative Association decision. SERC noted a particular challenge with deactivation–the inability to deactivate a registered entity that has an open enforcement action. There

Trends in the Activation and Deactivation of Functions – Table 2					
Regional Entity	**Registered Entities**		**Registered Functions**		**Trends in the Activation and Deactivation of Functions in the Regions during Assessment Period**
	2009	**2013**	**2009**	**2013**	
					appears to be no mechanism to transfer a function to an acquiring registered entity, even if the new owner has agreed to accept the compliance responsibility and mitigation of the prior issues. During the assessment period, SERC's Compliance Database Management Functional Group began seeking a solution to this limitation.
SPP RE	117	140	379	438	SPP RE registered 117 new functions and deactivated 66 functions during the assessment period. Over half of the activations were GO and GOP, due in large part (60%) to construction of new generation. A large majority of the de-activations were due to sales and mergers, which also led to some name changes.
TRE	216	224	337	440	TRE registered 37 percent of the entities in the ERCOT footprint for at least two functions. Registration deactivations occurred only for the GO, GOP, LSE, PSE, and transmission Oowner (TO) functions, the majority of which occurred during 2011 and 2012, and consisted mostly of the GO, GOP, and PSE functions.
WECC	471	474	1,258	1,250	Since January 1, 2010, WECC processed 239 registration requests, all of which were accepted and approved by NERC. WECC is forecasting that most DPs/LSEs connected via radial tie lines will request deactivation following the BES definition revisions. To help prepare for this anticipated influx, WECC introduced business process management software for the WECC Compliance Registration Process in 2013. Entities now complete a web-based registration form on the WECC.biz site that requires the entity to provide additional information and answer specific questions based on their request. The system delivers the information to a WECC engineer for review while updates are provided automatically to the applicant via template emails. Everything from the original application to the engineer's review notes and correspondence emails

Trends in the Activation and Deactivation of Functions – Table 2					
Regional Entity	**Registered Entities**		**Registered Functions**		**Trends in the Activation and Deactivation of Functions in the Regions during Assessment Period**
	2009	**2013**	**2009**	**2013**	
					are managed by the system thereby decreasing the processing time.
TOTALS	**1,865**	**1,929**	**4,545**	**4,807**	

Another important part of the Regional Entities' organization registration functions pertains to the joint registration organization (JRO) and coordinated function registration (CFR), both of which are intended to define the responsibilities and accountability among entities separately registered for the same function. Revisions to NERC ROP §507 and the addition of §508, approved by the Commission on June 10, 2010, helped to clarify the operations of both types of registrations during the assessment period.[35]

Specifically, ROP §507 allows an entity to register as a JRO on behalf of one or more of its members or related entities for one or more functions for which such members or related entities would otherwise be required to register, and, thereby, accept on behalf of such members or related entities all compliance responsibility for that function or those functions including all reporting requirements. Many of the registered entities that use the §507 process are cooperatives, municipalities, and other publicly owned utilities. For example, the Illinois Municipal Electric Agency is a JRO in RF, and accordingly is registered as a DP, LSE, and TO on behalf of certain of its municipal members.[36] As of end of the assessment period, all but two (NPCC and WECC) of the Regional Entities had registered a total of 30 JROs.[37] Otherwise, after the initial implementation, the program was fairly static, with few entities registering as JROs or changing their JRO status. For example, during the assessment period, (i) FRCC processed four JRO changes; (ii) FRCC, SERC, and TRE registered a few JROs; (iii) MRO registered one new JRO; and (iv) SPP RE registered no new JROs.

NERC ROP §508 allows multiple entities to register using a CFR for one or more Reliability Standard(s) or for one or more Requirements or sub-Requirements with particular Reliability Standard(s) applicable to a specific function. The Registration of the CFR is the complete Registration for each entity, and each entity must take full compliance responsibility for those standards or requirements or sub-requirements it has registered for in the CFR. For example, in 2010, TRE registered 13 entities as TOPs through CFR agreements. Each CFR is an agreement between ERCOT ISO and one other transmission entity that allocates responsibility

[35] *See North American Electric Reliability Corporation*, Docket No. RR10-8-000 (June 10, 2010) (unpublished delegated letter order).

[36] *See* the compliance audit report at http://www.nerc.com/pa/comp/Audit%20Repots%20DL/2013_public_RFC_MRRE_IMEA.pdf.

[37] *See* the *JRO Member Listing* Excel spreadsheet at http://www.nerc.com/pa/comp/Pages/Registration-and-Certification.aspx.

for TOP requirements between ERCOT ISO and that entity. The CFRs are updated regularly to account for changes in the body of applicable NERC Reliability Standards.[38]

As of end of the assessment period, 184 registered entities took advantage of coordinating their registered functions pursuant to ROP §508.[39] This represented 44 coordination agreements in all Regional Entities but one (FRCC), some of which crossed regional lines. For example, one CFR involved 31 registered entities located in three different Regional Entities (MRO, RF, and SERC). TRE had the largest number of registered entities (73) in the CFR program with 17 CFR arrangements. As was true for the JROs, with the exception of TRE, there was little activity in the CFR program during the assessment period. For example, MRO saw only one JRO convert to a CFR; SPP RE had just one new CFR register; NPCC had two new CFRs register; RF and SERC had a few new CFRs register; and WECC had three new CFR changes. In TRE, in 2010, 60 entities were registered as LSEs in a CFR agreement, and 14 entities were certified and registered as TOPs in a CFR agreement with ERCOT ISO. Since that time, TRE accepted additional CFR registrations.

Notwithstanding the Regional Entities' overall success in registering entities to ensure sufficient coverage of the BPS, the 2009 JRESA listed five areas where improvements could be made to the process of organization registration.[40] As now discussed, in the Regional Entities' opinion, these areas were largely and appropriately resolved during the assessment period by FERC-approved changes to the NERC ROP and by other Commission actions, or were overtaken or resolved by other events or activities.

a. The Scope of the Registration Criteria

FERC-approved changes to NERC ROP Appendix 5B addressed, at least in part, the issue of whether the registration criteria appropriately capture the users, owners, and operators of the BPS to ensure reliability. The current version (effective July 1, 2014) of the *Statement of Compliance Registry Criteria* (contained in ROP Appendix 5B) reflect review by NERC and the Regional Entities, in consultation with the stakeholders. This review aimed to determine if there should be a different threshold for materiality to the reliability of the BES and to determine if the compliance resources could be better prioritized by changes to the registration criteria.[41] Along these same lines, the Regional Entities supported the efforts of the Registration and Certification Functional Group, working with the NERC Board-appointed Compliance and Certification Committee's Organization Registration and Certification Subcommittee, to develop proposed changes to the registry criteria.

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[38] To assist in this process, each Regional Entity's website includes a link to NERC's website to access its *Requirement Applicability List for Coordinated Functional Registration*. *See* http://www.nerc.com/pa/comp/Pages/Registration-and-Certification.aspx.

[39] *See supra* note 37.

[40] *See* 2009 JRESA, at pp. 21-23.

[41] *See North American Electric Reliability Corporation*, 141 FERC ¶ 61,241 (2012) (approving revisions to NERC ROP).

Also, during the assessment period, the ERO's activities to address the scope of the registration criteria became entwined with the Order No. 773 proceeding, in which the Commission modified the BES definition to remove regional discretion, and established a bright-line threshold that includes all facilities operated at or above 100 kV.[42] Order No. 773 also approved revisions to the NERC ROP to create an exception process to add elements to, or remove elements from, the BES on a case-by-case basis, and established a process pursuant to which an entity may seek a determination by the Commission whether facilities are "used in local distribution" as set forth in the FPA. As relevant here, while recognizing that the registration criteria and the BES definition have different applications (to entities and facilities, respectively), the Regional Entities believe that Order No. 773 addresses many of the concerns that were raised in 2009. The new BES definition and exception process, for example, may resolve the issue of small entities whose facilities are not necessary for the reliable operation of the BES. Currently, the Regional Entities are working with NERC to review and offer corresponding revisions to the *Statement of Compliance Registry Criteria* in NERC ROP Appendix 5B, and develop an application and database for the BES definition exception process (BESnet) to promote efficiency and consistency in the implementation of the new definition.

b. Re-examination of Functional Model Definitions

The 2009 JRESA noted commenters' concerns about the Reliability Functional Model, namely that it is conceptual whereas registered entities have (for historical or business reasons) often aligned their operations differently.[43] To address these concerns, that self-assessment discussed increasing the granularity of registration so it would focus on the requirement level, instead of the standard level, but it also recognized that redefining the terms of various functions may be impractical as it would unlikely resolve the immense diversity of organizational structures in the industry. While NERC and the Regional Entities spent some time at first to examine these ideas, they appropriately put the exercise on hold during the assessment period in light of the significant amount of work required to create and implement the new BES definition and the exception process. Also, the Order No. 773 effort may serve the same purpose and provide an increase in granularity as contemplated by the suggestions made in 2009 to revisit the Functional Model. Finally, NERC and the Regional Entities plan to start in 2014, to review and

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[42] *See Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, Order No. 773, 141 FERC ¶ 61,236 (2012), *order on reh'g and clarification*, Order No. 773-A, 143 FERC ¶ 61,053 (2013), *order on reh'g and clarification*, 144 FERC ¶ 61,174 (2013), *appeal pending sub nom. People of the State of New York, et al. v. FERC*, No. 13-2316 (2nd Cir. filed June 12, 2013); *see also Revision to Electric Reliability Organization Definition of Bulk Electric System*, Order No. 743, 133 FERC ¶ 61,150 (2010), *order on reh'g*, Order No. 743-A, 134 FERC ¶ 61,210 (2011). On June 6, 2013, the Commission extended the effective date of the new definition, until July 1, 2014. *See Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, Order Granting Extension of Time, 143 FERC ¶ 61,231 (2013), *order on reh'g*, 146 FERC ¶ 61,070 (2014). On March 20, 2014, the Commission approved NERC's proposed revised definition of "bulk electric system." *See North American Electric Reliability Corporation*, Order Approving Revised Definition, 146 FERC ¶ 61,199 (2014).

[43] *See* http://www.nerc.com/pa/Stand/Functional%20Model%20Archive%201/Functional_Model_V5_Final_2009Dec1.pdf . The Reliability Functional Model is not approved by the Commission, and is not used by every Regional Entity.

clarify relationships between the functional model and the NERC ROP registration and certification directives (including Registry Criteria).

c. Oversight of Multi-Regional Entities

As pointed out in the 2009 JRESA, there are instances where an entity owns or operates BES facilities in two or more regions and thus is subject to multiple compliance programs, and there are businesses that have operations in all eight Regional Entities. To address the challenges raised by these situations, several of the Regional Entities partnered during the assessment period to coordinate more effectively their compliance and enforcement efforts with respect to multi-regional registered entities (MRREs). In particular, they developed a lead region model, in which the Regional Entities decide which one will lead the compliance and enforcement efforts for a given MRRE. For example, RF, MRO, and SERC agreed that RF would be the lead Regional Entity for Mid-continent Independent System Operator (MISO) due to the location of its headquarters and load, and the complex seams issues between the MISO and PJM Interconnection markets, while RF and MRO agreed that MRO would be the lead Regional Entity for American Transmission Company (ATC) due to the majority of ATC's transmission being located within MRO's footprint. In addition, during the assessment period, the Regional Entities worked closely with NERC to improve the coordination of compliance monitoring, mitigation, and enforcement without requiring change to the registration process. To this end, toward the end of the period, the Regional Entities developed *Recommended Guidelines for Multi-Region Entity Coordination*, which the ERO Executive Management Group approved in April 2014 for implementation across the ERO. Efforts are currently underway to develop template agreements between the affected Regional Entities and the notification to registered entities.

d. Transfer of Registered Entities between Regional Entities

Changes to NERC ROP §1208, approved by the Commission during the assessment period, on October 21, 2010, adequately addressed the issue of the appropriate conditions for the transfer of a registered entity from one Regional Entity to another.[44] In the order approving the changes, the Commission agreed with NERC that a registered entity does not have a right to choose the Regional Entity that will be its Compliance Enforcement Authority.[45] The Commission explained:

> In addition, as the Commission stated in Order No. 672, it is important that the footprint of a Regional Entity makes sense from a reliability perspective and does not overlap with another regional footprint. The Commission explained that any change in size, scope or configuration of a Regional Entity would constitute an amendment to the Delegation Agreement, and any such amendment would be

[44] *See North American Electric Reliability Corporation*, 133 FERC ¶ 61,061 (2010) (approving revised Delegation Agreements and changes to ROP, including §1208 governing Regional Entity transfer requests); *see also Nebraska Public Power District, et al*., 136 FERC ¶ 61,047, *order on reh'g*, 137 FERC ¶ 61,144 (2011) (denying NPPD's request to transfer from MRO to SPP RE).

[45] 133 FERC ¶ 61,061, at P 72.

> subject to review by the ERO and approval by the Commission. This process, under which the Commission must approve any change to the boundary of a Regional Entity to which the ERO has agreed, indicates that boundary changes should be carefully considered and should serve to improve the effectiveness or efficiency of the Regional Entities' and NERC's administration of reliability, and should not merely benefit an individual registered entity.[46]

The Regional Entities believe that ROP §1208 will assist them in maintaining a more stable structure for enforcing the reliability standards, and will therefore promote consistency of results.

e. Applicability of Reliability Standards to Federal Entities

The Commission's orders with respect to Southeastern Power Administration, the U.S. Army Corps of Engineers, and the Southwestern Power Administration generally resolved the related issues of: (i) the registration status of U.S. government agencies; (ii) compliance by those agencies with the Reliability Standards; and (iii) the application of penalties to those agencies found in violation of the Reliability Standards.[47] These decisions will greatly assist the Regional Entities in their efforts to ensure that such major users, owners and operators of the BES are held accountable for their actions regarding the reliability of that system.[48]

2. Organization Certification

Organization Certification is the process by which NERC and the Regional Entities ensure that an applicant to be a reliability coordinator (RC), balancing authority (BA), or transmission operator (TOP) has the tools, processes, training, and procedures to demonstrate its ability to meet the Requirements and sub-Requirements of all of the Reliability Standards applicable to the function(s) for which it is applying, thereby demonstrating the ability to become certified and then operational. The specific requirements for this process are found in the NERC ROP Organization Registration and Certification Programs (§500), and *Organization*

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[46] *Id.*

[47] *See Southeastern Power Administration, 125 FERC ¶ 61,294 (2008)* (affirming SERC's registration of SEPA as a transmission operator and resource planner*); North American Electric Reliability Corporation*, 133 FERC ¶ 61,214 (2010), *order on reh'g*, 137 FERC ¶ 61,044 (2011); *North American Electric Reliability Corporation*, 129 FERC ¶ 61,033 (2009), *order dismissing reh'g*, 130 FERC ¶ 61,002 (2010) (collectively, affirming TRE's and SPP RE's decisions to register the U.S. Army Corps of Engineers and finding that any other federal entity that uses, owns or operates the BPS must comply with mandatory Reliability Standards); *North American Electric Reliability Corporation*, 140 FERC ¶ 61,048, *order on reh'g*, 141 FERC ¶ 61,242 (2012) (finding that SWPA was liable for a $19,500 penalty imposed by SPP RE for violating Reliability Standards), *appeal pending sub nom. Southwestern Power Administration, et al.* v. *FERC*, No. 13-1033 (D.C. Cir. Feb. 15, 2013).

[48] The implication of these decisions on the Regional Entities' workload is apparent from the statistics in NERC's May 8, 2013 PowerPoint presentation titled on *Key Compliance and Enforcement Metrics and Trends*. At that time, there were 419 open federal entity possible violations under review, of which 373 or 89% were "on hold" because the legal issues had not been resolved. Fortunately, the registered entities had mitigated or were in the process of mitigating 86 percent of the possible violations.

Registration and Certification Manual (Appendix 5A), and are also set out in the *ERO Certification and Review Procedure* manual (updated May 12, 2014).[49] Accordingly, the Regional Entities must organize certification teams that are subject to certain training requirements to ensure the accuracy of the certifications.[50] As is true of the registration process generally, the organization certification process ran smoothly during the assessment period. In that time, the Regional Entities certified 53 entities, conducted 68 reviews, and received only three objections to a Regional Entity's certification team's decision.[51]

F. Compliance Monitoring and Enforcement Program

The 2009 JRESA discussed the Regional Entities' implementation of the CMEP, covering ten topics: (i) compliance registry; (ii) consistency and use of discretion in application of penalties; (iii) CMEP consistency; (iv) compliance audit consistency; (v) consistency in interpretation of Reliability Standards; (vi) compliance caseload backlog; (vii) treatment of minor violations; (viii) compliance information management tools; (ix) compliance process transparency (within the ERO and the Regional Entities and between the ERO and its registrants); and (x) the hearings and appeals process.[52] The following updates that discussion, and provides additional information on the Regional Entities' progress to implement and improve the CMEP.[53]

1. Development and Status of the Compliance Monitoring and Enforcement Program

During the assessment period, the Regional Entities made significant progress and improvements in the implementation of the CMEP. This is important because the CMEP represents the Regional Entities' primary responsibility under the FPA and the Commission's regulations. FPA §215(a)(7), 16 U.S.C. §824o(a)(7), defines "regional entity" in the first instance as "an entity having enforcement authority" under the relevant statutory provisions. §39.1 of the Commission's regulations, 18 C.F.R. §39.1, repeats that definition. Accordingly, during the assessment period, the Regional Entities devoted the majority of their resources to oversee compliance with and enforcement of the mandatory Reliability Standards.

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[49] *See* http://www.nerc.com/pa/comp/Pages/Organization-Certification.aspx.

[50] *Id.* pp. 5-6

[51] These numbers break down by Regional Entity as follows:

	FRCC	MRO	NPCC	RF	SERC	SPP RE	TRE	WECC
Number of Certifications	0	1	3	5	10	3	18	13
Number of Reviews	4	7	4	11	17	4	4	17
Number of Appeals	0	0	0	0	0	1	0	2

[52] *See* 2009 JRESA, at pp. 21-31.

[53] The update to the section on Compliance Registry, included in the CMEP discussion in the 2009 JRESA, is found in the previous section of this self-assessment.

The Commission explained NERC's and the Regional Entities' roles in regard to the CMEP in its 2007 order accepting the initial RDAs and approving the original formulation of the CMEP.[54] In brief, NERC relies on the Regional Entities to enforce the NERC Reliability Standards with BES owners, operators, and users through approved RDAs. Regional Entities are responsible for monitoring compliance of the registered entities within their regional boundaries, assuring mitigation of all violations of approved Reliability Standards, and assessing penalties and sanctions for failure to comply. For that purpose, the CMEP specifies monitoring processes, including: (i) compliance audits; (ii) self-certification; (iii) spot checking; (iv) investigations; (v) self-reporting; (vi) periodic data submittals; and (vii) complaints.[55] It also includes procedures for enforcement actions, mitigation of violations, and remedial action directives, data retention, and confidentiality matters. In addition, the CMEP obligates each Regional Entity to establish and maintain a hearing body to conduct and render hearings concerning disputes over findings of alleged violations, proposed penalties, and mitigation plans.[56]

The Regional Entities have unwaveringly taken their compliance monitoring and enforcement responsibilities very seriously. In the beginning, they especially relied on their experience in conducting audits, and worked closely with NERC and the Commission's enforcement staff to structure their enforcement activities to ensure that the registered entities complied with the reliability standards. In addition, they increased their staffs to have adequate resources. More resources were necessary in part because the Regional Entities, while recognizing that they had discretion to determine appropriate remedies, conducted their enforcement programs with the understanding that they should investigate every possible violation of a standard or one of its requirements and compile a record sufficient to support any remedy chosen for a violation.[57] This was true regardless of the severity of the violations or the risk they posed to reliability. This was true even if the violations were simply a matter of documentation deficiencies.

No one in the reliability community, including FERC and NERC staff and the personnel at the Regional Entities and the registered entities, anticipated the number of violations that the Regional Entities would ultimately discover. When the 2009 JRESA was submitted to the Commission, the Regional Entities had amassed a significant backlog of over 1,700 violations. Clearly, as NERC and the Regional Entities recognized, this was an unacceptable situation.

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[54] *See North American Electric Reliability Corporation, et al*., Order Accepting ERO Compliance Filing, Accepting ERO/Regional Entity Delegation Agreements, and Accepting Regional Entity 2007 Business Plans, 119 FERC ¶ 61,060 (2007).

[55] Early in the program, the monitoring processes also included "exception reporting," which was eliminated by a change in the NERC ROP, approved by the Commission in December 2012. *See North American Electric Reliability Corporation*, Order Conditionally Approving Revisions to North American Electric Reliability Corporation Rules of Procedure, 141 FERC ¶ 61,241 (2012).

[56] *See* 119 FERC ¶ 61,060 (2007), at P 26.

[57] *See generally Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Statement of Administrative Policy on Processing Reliability Notices of Penalty and Order Revising Statement in Order No. 672, 123 FERC ¶ 61,046 (2008); Guidance on Filing Reliability Notices of Penalty, 124 FERC ¶ 61,015 (2008).

Within the following year, after many discussions and meetings between and among FERC, NERC, and Regional Entity staffs, and stakeholders, NERC and the Regional Entities were on their way to figuring out how to reduce that backlog, and, more to the point, to address the overarching issue of how much discretion the Regional Entities could exercise in the implementation of the CMEP.

In Fall 2009, several months after NERC had submitted its Three-Year ERO Performance Assessment Report, the Commission took three actions that set the stage for NERC and the Regional Entities to improve their implementation of the CMEP: (i) it provided further guidance on filing proposed penalties, and stated the agency's willingness to consider an abbreviated format for submitting certain types of NOPs;[58] (ii) it issued Order No. 728, which delegated to the FERC Enforcement Director authority to allow routine NOPs to become effective and to stay the effectiveness of NOPs when it was necessary to seek further information;[59] and (iii) it issued an order allowing 564 proposed penalties (labeled the "omnibus filing") to become effective by operation of law.[60]

In 2009 through 2012, the Commission issued additional orders providing direction to the members of the reliability community on what was expected of them and what they could expect from the Commission. These orders covered a variety of issues, including the importance of a mitigation record,[61] the implications of a registered entity's repeat violations and violations by its affiliates,[62] the Regional Entities' responsibility to examine a registered entity's compliance program when determining an appropriate remedy,[63] the need for Regional Entities to consider load loss and harm to customers resulting from violations of Reliability Standards in their penalty assessments for these violations,[64] and the recovery of penalties from third-parties doing business in RTOs and ISOs.[65]

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[58] *See* Further Guidance Order on Filing of Reliability Notices of Penalty, 129 FERC ¶ 61,069 (2009).

[59] *See* Delegations for Notices of Penalty, Order No. 728, 129 FERC ¶ 61,094 (2009). Subsequently, the Commission transferred the delegation from the Director of the Office of Enforcement to the Director of the Office of Electric Reliability. *See* Delegation of Authority Regarding Consideration of Notice of Penalty, Order No. 795, 146 FERC ¶ 61,083 (2014).

[60] *See North American Electric Reliability Corporation*, Order on Omnibus Notice of Penalty Filing, 129 FERC ¶ 61,119 (2009).

[61] *See North American Electric Reliability Corporation*, Order Accepting Notices Of Penalty, 126 FERC ¶ 61,014 (2009).

[62] *See North American Electric Reliability Corporation*, Notice of No Further Review and Guidance Order, 132 FERC ¶ 61,182 (2010).

[63] *See* Delegated Letter Order, 133 FERC ¶ 62,037 (2010). *See also North American Electric Reliability Corporation*, 134 FERC ¶ 61,146 (2011).

[64] *See Northern American Electric Reliability Corporation*, 134 FERC ¶ 61,209 (2011), *order on reh'g and clarification*, 139 FERC ¶ 61,248 (2012).

[65] *See Reliability Standard Compliance and Enforcement in Regions with Regional Transmission Organizations or Independent System Operators*, Order Providing Guidance on Recovery of Reliability Penalty Costs by Regional Transmission Organizations and Independent System Operators, 122 FERC ¶ 61,247 (2008); *see also PJM*

The omnibus filing eventually led to the Regional Entities' compiling processed violations on spreadsheets entitled Administrative Citation NOPs, an approach approved by the Commission in March 2011.[66] The Commission's statements at that time provide the status of NERC's and the Regional Entities' implementation of the CMEP:

> The Commission recognizes that NERC and the Regional Entities expend substantial efforts and resources monitoring compliance with the Reliability Standards and building adequate records to support findings of violations for Commission review. On numerous occasions, the Commission has encouraged NERC and the Regional Entities to develop flexible approaches and more streamlined processes to achieve efficiency in the enforcement process, especially with regard to more minor violations. NERC has adopted an Abbreviated Notice of Penalty format and a Deficiency Notice of Penalty format that have been successful at increasing efficiency. Based upon this filing, we believe that NERC's Administrative Citation Notice format will be a successful tool in improving efficiency of NERC's enforcement process, thereby reducing the time and resources expended by the Regional Entities, NERC, and Commission staff while still achieving transparency and consistency in penalty determinations for violations that are appropriate for this format. We also commend NERC for promptly following through with its intent to institute the Administrative Citation process.
>
> We encourage NERC's continued use of the Administrative Citation Notices of Penalty format. We also encourage, particularly in the early stages of this process, the ongoing consultation between our staff and NERC prior to filing to determine what violations are appropriate for inclusion in an Administrative Citation Notice of Penalty and the appropriate amount of detail and description necessary to ensure that the Administrative Citation process continues to be a success.[67]

Six months later, in September 2011, Administrative Citation NOPs transitioned into Spreadsheet NOPs (SNOPs). Candidates for inclusion in an SNOP are those violations that posed minimal or moderate risk to the reliability of the BPS. In all cases, the SNOP sets forth whether the violations have been mitigated, certified by the respective registered entities as mitigated, and verified by the Regional Entity as having been mitigated. During the assessment period, the Regional Entities processed and submitted through NERC 5,128 confirmed violations in NOPs to the Commission, using the Administrative Citation NOP format for 296 and the

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Interconnection, L.L.C., Order Accepting Tariff Revisions and Requiring Compliance Filing, 124 FERC ¶ 61,260 (2008) and *Midwest Independent Transmission Operator, Inc*., Order Conditionally Accepting Proposed Tariff Revisions, 128 FERC ¶ 61,229 (2009).

[66] *See North American Electric Reliability Corporation*, Notice of No Further Review of Initial Administrative Citation Notice Of Penalty, 134 FERC ¶ 61,157 (2011).

[67] *Id.* PP 7-8 (footnotes omitted).

SNOP format for 1,428 of those violations. For the 27 months from September 30, 2011 to December 31, 2013, the use of SNOPs alone represented 58% of the total number of NOPs submitted to the Commission.[68]

The next phase in the evolution of the ERO Enterprise's implementation of the CMEP is reflected in the FFT program, which started as the centerpiece of NERC's Compliance Enforcement Initiative (CEI). Details of this program during the assessment period are found primarily in two Commission orders—one issued in March 2012 and one issued in June 2013—and the NERC filings addressed by those orders.[69] Candidates for FFT treatment are possible violations that pose minimal or moderate risk to reliability and have been fixed. A certification of completion of the mitigation activities is submitted, at least within 90 days from the date the FFT is filed or posted, by the respective registered entity for every FFT submission.[70]

Again, the Commission's statements in these FFT orders are evidence of the progress made by NERC and the Regional Entities in the implementation of the CMEP. In the March 2012 order, the Commission explained,

> While the FFT initiative represents a significant change in the paradigm for monitoring and enforcing compliance with Reliability Standards, we agree with NERC that this change is warranted at this time. After several years of experience with the current program, we agree that NERC and the Regional Entities should have the flexibility to more efficiently process and track lesser risk violations in order to focus their resources on issues that pose the greatest risk to reliability.[[71]]

In its June 2013 order, the Commission found, "[b]ased on the information provided in NERC's filing… the FFT program is improving the ability of NERC and its Regional Entities to more efficiently process lesser-risk possible violations, enabling them to reduce the backlog of pending enforcement cases and focus on issues of greater importance to bulk-power system reliability."[72] Notably, in that order, the Commission explained that its staff had reviewed a

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[68] *See* http://www.nerc.com/pa/comp/CE/Pages/Enforcement-and-Mitigation.aspx.

[69] *See North American Electric Reliability Corporation*, Order Accepting with Conditions the Electric Reliability Organization's Petition Requesting Approval of New Enforcement Mechanisms and Requiring Compliance Filing, 138 FERC ¶ 61,193 (2012); *North American Electric Reliability Corporation*, Order on Compliance Filing, 143 FERC ¶ 61,253 (2013).

[70] Originally, as approved by the Commission, the FFT program only pertained to possible violations with minimum risk; however, in the June 2013 order, the Commission approved NERC's proposal to expand coverage to possible violations that pose moderate risk to reliability, subject to NERC's submitting a report by June 20, 2014, justifying a continuation of the expansion of the program. The Commission likewise approved NERC's proposal to allow FFT treatment even before mitigation is completed provided it is completed within 90 days of the time when the FFT is filed or posted. *See* 143 FERC ¶ 61,253, at PP 32-34, 36-37.

[71] 138 FERC ¶ 61,193, at P 2 (footnote omitted).

[72] 143 FERC ¶ 61,253, at P 27.

sample of 100 FFT issues out of approximately 820 FFT issues filed with the Commission between September 2011 and September 2012, and determined that the Regional Entities properly treated those possible violations under the FFT program.[73]

As recognized by the Commission, the Regional Entities generally believe that the FFT program significantly improved the processing of violations of the reliability standards during the assessment period, and enabled them to focus resources and attention on more serious and complex matters.[74] During the assessment period, they processed total of 1,762 possible violations using the FFT procedures, which, in 2012 and 2013, respectively, represented 48% and 43% the total number of violations and possible violations processed by the Regional Entities. In addition, the FFT program had a positive impact on processing time, which was a major concern identified by the registered entities in 2009. In this regard, between January 1, 2012 and September 30, 2013, the average time for disposing of FFTs was 7.4 months as compared to 10.7 months for SNOPs and 13.1 months for NOPs.[75]

The Commission spoke favorably of the FFT program after its review in 2013, and encouraged NERC to continue to improve the program and report back to the Commission by June 20, 2014. Specifically, the Commission directed NERC to monitor the Regional Entities' eligibility determinations; requested more specificity regarding the FFT program's impact on BPS reliability; encouraged NERC to continue to work with the Regional Entities to improve and better coordinate their risk assessments; and stressed that NERC should continue its outreach to the Regional Entities to encourage the use of self-reports by the registered entities.[76] For their part, to a certain extent in response to the Commission's review, the Regional Entities elicited from focus groups other specific issues that they believed needed to be addressed in general or in certain Regional Entities as NERC and they continued to refine the program. These included overall processing time, the full mitigation plan requirement, insufficient information on content and process, no centralized information collection (particularly for MRREs), and inadequate communication during the process. The Regional Entities are committed to continue working closely with NERC and registered entities to address these issues and to bring about continuous improvement in the FFT program and related efforts.[77]

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[73] *Id.* P 31. Between December 6, 2013 and December 16, 2013, in Docket No. RC11-6-000, *et al*., all eight Regional Entities responded to the Commission's annual FFT survey to collect data on the effectiveness and efficiency of the FFT program. Each response included data, correspondence, and other supporting information used by the Regional Entity staffs to evaluate and conclude that the previously submitted possible violations identified by FERC staff qualified for FFT treatment. The Commission's response to these filings was still pending at the end of the assessment period.

[74] *See* Attachment A to NERC's Report in Docket No. RC11-6-004, for information from each Regional Entity on the impact of the FFT program on its region. *See* also 143 FERC ¶ 61,253, at PP 8-9 (describing the information gleaned from Attachment A).

[75] *See* the PowerPoint presentation titled *Key Compliance and Enforcement Metrics and Trends,* Compliance Committee Meeting, November 6, 2013, at slide. 5.

[76] *See* 143 FERC ¶ 61,253, at PP 28-30.

[77] Indicative of the progress made to date is reflected in the Key Compliance Monitoring Index (KCMI) compiled by NERC, which reported that as of the end of 2012, 5,115 confirmed violations were processed for the period beginning June 18, 2007. Of these violations, 85 percent had minimal impact to reliability, 13 percent had moderate

The ERO Enterprise's next advancement in CMEP implementation is RAI. Started in late 2012, RAI is intended to transform the current compliance and enforcement program into one that is forward-looking, focuses on high reliability risk areas, simplifies compliance for registered entities, and creates alternative paths outside of enforcement to resolve minor matters. Accordingly, RAI has three main goals:

(1) Develop enforcement incentives to recognize positive behavior that contribute to higher accountability and improved performance and discourage poor performance;

(2) Design and scope compliance programs that recognize risk to reliability, including consideration of an entity's management controls and corrective action programs used to meet the reliability standards; and

(3) Reduce unnecessary compliance and enforcement activities while gaining efficiencies.

As much if not more than any CMEP project undertaken since 2007, RAI is a collaborative and coordinated effort of the ERO, the Regional Entities, and the registered entities, without regard to ownership, but rather with an objective of working on a common set of deliverables.

A statement made at the July 9, 2013 FERC Reliability Technical Conference accurately portrays the situation in which the Regional Entities find themselves daily in their efforts to enforce the reliability standards, and serves as a backdrop to RAI:

> Simply put, we know the current zero tolerance approach is not sustainable for the long term….[O]ur current processes tend to be backward-looking, and we need to move to a space where we're more forward-looking to really assess an entity's ability to stay in compliance and meet or exceed the reliability standards.[78]

As further discussed at the conference, RAI would not allow "small stuff" to be "swept under the rug." The "small stuff" matters. The expectation is that the registered entities would have management practices in place to resolve the "small stuff" before it becomes a reliability risk in the form of a material violation of a Reliability Standard. To this end, the Regional Entities would look to how well a registered entity meets the reliability objectives of the standards, and whether any identified violations rise to the level that needs enforcement. It would allow Regional Entities to, among other things, better tailor the scope of audits and other

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impact, and 2 percent had serious impact. Furthermore, the five-year assessment of the KCMI indicated that the risk to BPS reliability based on the number of violations of NERC Reliability Standards trended lower from 2008 to 2012. *See* NERC's *State of Reliability 2013* report (May 2013), http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2013_SOR_May%2015.pdf, at p. 6.

[78] Testimony of Mark Rossi, Senior Vice President and Chief Operating Officer, NERC, Transcript of Reliability Conference (July 9, 2013), Docket Nos. AD13-6-000, *et al.*, at p. 86.

compliance monitoring activities based on an entity's risk (e.g., size, complexity of operations, and effectiveness of internal controls).[79] It would also provide for the determination of the nature of enforcement actions to be based on risk and the presence of internal controls. For example, a single missing record (out of hundreds) for maintaining and testing protection systems that is proactively identified and recorded by the registered entity as part of its normal management practices might not rise to an enforcement matter. While the matter would be part of the entity's compliance record, it would likely not require an enforcement filing. Traditional methods of enforcement and application of penalties, however, would still be used in connection with matters that pose a serious or substantial risk to the BPS. For those matters, the full NOP or SNOP would remain available.[80]

Starting in March 2013, several Regional Entities and registered entities became engaged in pilot programs as the initial steps towards full RAI implementation. In this regard, the Regional Entities appreciate that the Commission has previously recognized the value of pilot projects, pointing out that "[n]o matter how good the data suggesting that a regulatory change should be made, there is no substitute for reviewing the actual results of a regulatory action."[81] With this in mind, each pilot project endeavored to further define the risk-based approach and develop effective tools, training, procedures, and policies to allow the ERO Enterprise to deploy these concepts in a consistent manner across all Regional Entities. The ERO Enterprise intends to keep the Commission apprised of the progress of the pilot projects, and will make appropriate revisions and submit any necessary filings with the Commission to establish a common framework throughout the ERO Enterprise.

In sum, in the ERO Enterprise's opinion, there are significant benefits to be gained through RAI, including better alignment to a culture of reliability. RAI would give credit to entities that demonstrate strong management practices and a culture of complying with the reliability standards. Similarly, the program would focus compliance monitoring on areas that pose the greatest risk to reliability, thereby enabling and encouraging an entity to address areas of higher risk by strengthening management practices around those risks. This in turn should result in a more effective program addressing risks to reliability consistent with internal control approaches used in other areas of the corporation.[82]

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[79] *Id.* pp. 86-87.

[80] *See* Reliability Assurance Initiative, *White Paper [No. 5] Change State Element No. 4 - Redesign of the Enforcement Strategy* (March 13, 2013), at p. 4, located at http://www.nerc.com/pa/comp/Pages/Reliability-Assurance-Initiative.aspx.

[81] Order No. 637, FERC Stats. & Regs. ¶ 31,091 (2000), at p. 31,279. The U.S. Court of Appeals for the D.C. Circuit agrees: "For at least 30 years this court has given special deference to agency development of such experiments, precisely because of the advantages of data developed in the real world." *Interstate Natural Gas Association of America v. Federal Energy Regulatory Commission*, 285 F.3d 18, 24 (D.C. Cir. 2001).

[82] *See* generally http://www.nerc.com/pa/comp/Pages/Reliability-Assurance-Initiative.aspx. In this regard, the Regional Entities appreciate the Commission's recognition of the RAI's potential benefit. Toward the end of the assessment period, the Commission noted that "…the [RAI] process when fully developed may afford a consistent, informed approach that provides incentives for entities to develop robust internal control programs." *Version 5 Critical Infrastructure Protection Reliability Standards*, Order No. 791, 145 FERC ¶ 61,160 (2013), at P 73 (footnote omitted).

Along with developing the RAI toward the end of the assessment period, NERC and the Regional Entities focused on three other major areas: (i) the development of a single ERO-wide audit process checklist and associated auditor handbook to ensure the use of more consistent processes and procedures by the staff in the field; (ii) the implementation of the FFT enhancements approved by the Commission in its June 20, 2013 order in Docket No. RC11-06-004; and (iii) the improvement in the self-reporting processes, including reducing the burden and cost of self-reporting. The Regional Entities, as part of the ERO Enterprise, made the following progress in each of these areas:

a. Development of Single ERO-Wide Audit Process Checklist and Associated Auditor Handbook

As the Regional Entities recognized in 2009, work was needed to ensure the consistency of compliance audits.[83] Accordingly, as discussed below, they worked on numerous projects within their own regions and across regions to improve their major tool to ensure compliance with the mandatory Reliability Standards. As relevant here, in September 2012, the Regional Entities engaged an outside firm to assess the current state of regional compliance audit procedures and underlying processes, and make recommendations that could lead to more consistent audit practices across the Regional Entities and better position them to adapt to future regulatory changes and demands. This engagement dovetailed with the development of the white papers and other conceptual documents underlying RAI, and naturally became part of the larger effort to revisit the CMEP paradigm. The outside firm produced its assessment (referred to as the Third-Party Assessment) in February 2013, and recommended that the Regional Entities:

(1) Develop a single set of standardized audit methodology documents to be used across the ERO, after aligning their existing audit methodologies;

(2) Deploy a pilot program to assess and implement the standardized audit checklist; and

(3) Roll out a robust training program to provide the audit community with sufficient growth opportunities and ultimately guide auditors in the interpretation and optimal application of the audit guidance and checklist.

Subsequently, with NERC's support and cooperation, during the assessment period, the Regional Entities produced a standard *Compliance Auditor Checklist* and completed the first version of a common *Compliance Auditor Handbook*, as found in the *ERO Enterprise Compliance Auditor Manual*.[84] Also, certain Regional Entity staffs participated in pilot or

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[83] *See* 2009 JRESA, at p. 25.

[84] *See* http://www.nerc.com/pa/comp/ERO%20Enterprise%20Compliance%20Auditor%20Manual%20DL/ERO_Enterprise_Compliance_Auditor_Manual_version_1.pdf.

comparable programs to see how the audit process checklist worked in the field, and collaborated with their colleagues in other Regional Entities to fashion appropriate training materials. The Regional Entities firmly believe that the use of the audit process checklist and handbook will create a standardized process that will improve efficiencies and drive consistency while ensuring that audits conform to professional auditing standards, particularly the Generally Accepted Government Accounting Standards (GAGAS).

b. Implementation of FFT Enhancements

As noted earlier, in the June 2013 FFT order, the Commission approved, with conditions, four enhancements to the FFT program.[85] The Commission permitted an expansion of the program by allowing FFT treatment for a "limited pool" of possible violations involving moderate (in addition to minimal) risk, subject to NERC's filing a report by June 20, 2014, justifying the continuation of the expanded FFT program; allowed the inclusion of possible violations as FFTs even if the mitigation was not yet completed, provided the mitigation was completed within 90 days from the date the FFT is filed or posted; permitted the Regional Entities to publicly post FFTs on a common website on the last business day of each month instead of NERC submitting a monthly informational filing to the Commission; and agreed with NERC's proposal to review a representative sample of FFTs during the 60-day window following the Regional Entities' monthly posting of FFTs on NERC's website instead of reviewing each FFT before public posting. In July 2013, immediately after the issuance of the June 2013 order, the Regional Entities began implementing the approved FFT enhancement applicable to them. Specifically, they included FFTs where mitigating activities had not yet been completed, submitted monthly FFT compilations to NERC for posting on its website, and evaluated possible violations involving moderate risk for processing as FFTs.[86]

c. Improvement in the Self-Reporting Process

As NERC President and CEO Gerry Cauley pointed out at the July 9, 2013 FERC Technical Conference, two-thirds of all violations at that time were self-reported.[87] Nevertheless, at that conference and in other forums such as the FERC FFT proceedings and NERC and regional meetings with the registered entities, the need to improve the self-report process was often stressed. Accordingly, the Regional Entities took steps to meet that need. To start with, as mentioned earlier, they identified areas for potential improvements. These included a lack of sufficient information on content in self-reports both in the details of the violation and the risk assessment information. In addition, there was a perception in certain cases of a lack of centralized information collection (particularly for MRREs), and the registered entity complaints on the combination of long overall processing time and a lack of communication throughout the process.

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[85] *See* 143 FERC ¶ 61,253 (2013). The Commission rejected one of NERC's proposals, to eliminate senior officer certification. *Id*. P 17.

[86] *See* http://www.nerc.com/pa/comp/CE/Pages/Enforcement-and-Mitigation.aspx for the FFT postings.

[87] *See* Transcript of Reliability Conference (July 9, 2013), Docket Nos. AD13-6-000, *et al*., at p. 135. Self-reports in this context also includes self-certifications.

Next, the Regional Entities worked together, with NERC, and with a focus group of registered entities to start putting in place enhancements to the self-report process. These included:

(1) Additional guidance on processing and the content of self-reports;

(2) Points of contact at the Regional Entity for additional guidance;

(3) An improved intake form that has the capability of augmenting information and cross-referencing information already provided, and a centralized process for MRREs; and

(4) Aggregation of minimal risk issues by selected registered entities in selected Regional Entities to allow training on risk assessment and mitigation development.

Significantly, by the end of the self-assessment period, with input from the industry focus group, NERC and the Regional Entities completed a draft of the *ERO Self-Report User Guide*, which was posted for broader stakeholder comment in January 2014. As explained in the posting, this user guide should provide registered entities with valuable information and insight on what to do to facilitate disposition of possible noncompliance by the ERO Enterprise.[88] Subsequently, in April 2014, NERC posted a revised *ERO Self-Report User Guide* with the express purpose of enhancing the Registered Entities' understanding of the information necessary for NERC and the Regional Entities to provide efficient and timely resolution of instances of potential noncompliance.[89]

2. Updates to the 2009 Joint Regional Entity Self-Assessment

As described above, the 2009 JRESA addressed nine separate CMEP topics, in addition to the compliance registry. Four involved achieving consistency within the program (consistency and use of discretion in application of penalties, CMEP consistency, consistency in interpretation of reliability standards, and compliance audit consistency), four dealt with enforcement issues (caseload backlog, treatment of minor violations, information management tools, and process transparency), and one reviewed the hearing and appeals process. Because the previous discussion on the progress made by NERC and the Regional Entities on streamlining and improving the CMEP addresses or otherwise touches on most of these topics, the following will not repeat relevant parts of that discussion here. Rather, it will provide updates to specific topics and issues that were raised by the Commission, NERC, the Regional Entities themselves, or stakeholders, in 2009. The discussion is organized under the topics of: (i) Consistency; (ii) Compliance Monitoring; (iii) Enforcement; and (iv) Hearings and Appeals.

[88] *See* http://www.nerc.com/pa/comp/Pages/Reliability-Assurance-Initiative.aspx.

[89] *See* http://www.nerc.com/pa/comp/Reliability%20Assurance%20Initiative/ERO%20Self-Report%20User%20Guide%20(April%202014).pdf.

a. Consistency

In the 2009 JRESA, the Regional Entities identified consistency as an overarching issue in their discussion of the CMEP. That discussion, of course, reflects their recognition that the Commission has repeatedly tasked NERC to ensure consistency of compliance across the Regional Entities, and the NERC ROP explicitly provide that NERC must have a program to monitor the compliance enforcement efforts of each Regional Entity to achieve that objective. Accordingly, in 2009, the Regional Entities examined the issue from several different perspectives. Taken as a whole, these examinations break down into an understanding of the concept of consistency as a general matter and the efforts of the Regional Entities to achieve consistency within their own regions and across regions. To reiterate, what is now described is in addition or complementary to the ERO Enterprise's efforts to develop the RAI.

Consistency as a General Matter

The Regional Entities are committed to working within their own areas, across regions, and with NERC to meet the Commission's expectation that their compliance monitoring and enforcement endeavors adhere to the same principles, course, and form. That said, they also are aware, and urge the Commission and NERC to recognize, that consistency does not necessarily mean exactness in results. Indeed, the adoption of a risk-based approach to the CMEP, as introduced in NERC's 2011 through 2013 annual CMEP Implementation Plan,[90] will naturally result in different treatment of different entities and different outcomes of compliance and enforcement activities. Specifically, for example, penalty consistency does not mean the same penalty for specific alleged violations across all Regional Entities, because the risk posed by a specific alleged violation varies depending on the characteristics of the Regional Entity's footprint, the registered entity and its geographical location and interconnection, as well as other pertinent facts and circumstances. Instead, in the Regional Entities' opinion, penalty consistency must focus on the need for a uniform methodology to ensure that the penalty for each violation (i) is consistent with the risk posed by that violation, and (ii) encourages the appropriate behavior to improve the reliability of the BES.

Consistency of Remedies <u>Within</u> the Regions

While sensitive to consistency in their work generally, the Regional Entities expended considerable resources and paid special attention during the assessment period to ensure that their determinations on appropriate remedies for violations of the mandatory reliability standards were consistent within their own regions. For that purpose, they all used internal case management systems, which were similar in that they involved methodical comparisons of the violations to actual penalties assessed for violations of the same or similar standards or requirements within the Regional Entity; directed their staffs to coordinate and otherwise participate in regular meetings of the regional stakeholder compliance committees; required review or "sign off" by senior regional managers; and stressed internal training and regular

[90] *See*, e.g., *ERO Compliance Monitoring and Enforcement Program 2013 Implementation Plan* (revised December 27, 2012) at http://www.nerc.com/pa/comp/Resources/Pages/default.aspx?View={cb5b1d3f-f5b7-421d-8266-0bcf6a06fc08}&SortField=Date&SortDir=A.

communications with and outreach to their registered entities. They also developed other specific means for achieving the objective of consistent remedial determinations, such as compiling and posting frequently asked questions (FAQs), using surveys, involving technical experts to address risk and harm, assigning a single point of contact for each registered entity, and separating their compliance and enforcement staffs.

Consistency of Remedies and Other Matters Across the Regions

The Regional Entities made substantial progress during the assessment period to improve CMEP consistency by increasing their interaction with each other. Notable accomplishments in this regard were made by the REMG, which proactively and persistently stressed the importance of information sharing, transparency, and consistency within and among Regional Entities, and working collaboratively with NERC. In addition, as mentioned earlier, several of the Regional Entities partnered to coordinate more effectively their compliance and enforcement efforts with respect to MRRE. In this regard, they developed a lead region model, in which the Regional Entities decide which one will lead the compliance and enforcement efforts for a given MRRE.[91] Further, the Regional Entity staffs regularly met with each other to promote consistency with CMEP processes and provide subject matter experts, as needed, to the same end, and conducted compliance workshops to which the registered entities from other regions were welcomed. They also collaborated on improving data management tools and the various forms used by the Regional Entities and the registered entities, including the self-report and the self-certification forms and, as discussed in greater detail below, the reliability standards audit worksheets (RSAWs).

Finally, and as apparent from the previous discussion of the developments in the CMEP during the assessment period, the Regional Entity staffs actively participated in NERC-led committees, task forces, and working groups. For example, the Regional Entities actively participated during the assessment period is the Enforcement Sanctions and Mitigation Working Group (ESMWG). This group reviews one or two Regional Entity enforcement processes during an in-person meeting, and then shares its review to help identify best practices and highlight areas where consistency could be improved. NERC Enforcement staff also participates in these meetings and is present for discussions regarding variations in approach to enforcement and mitigation responsibilities. Additionally, the ESMWG conducts periodic "risk assessment" exercises whereby each Regional Entity is asked to review particular fact patterns and descriptions of mitigating activities and assign the appropriate level of risk. Regional Entities are further asked to highlight any assumptions that are made or to identify additional information that would assist in the assignment of the risk posed by the particular facts and circumstances. Not only do these exercises provide value in driving consistency in assessment of risk, they highlight areas of improvement in the drafting of descriptions of violations, mitigating activities, and risk assessments. By becoming involved in in-depth analyses and discussions of potential and actual risk, the Regional Entities aim to continuously improve the final enforcement product.

[91] For example, RF, MRO, and SERC agreed that RF would be the lead Regional Entity for MISO", while RF and MRO agreed that MRO would be the lead Regional Entity for ATC".

b. Compliance Monitoring

During the assessment period, the Regional Entities steadfastly used their major tool to monitor compliance with the mandatory Reliability Standards—compliance audits of the registered entities. They also used other compliance monitoring tools, including: (i) spot checks; (ii) self-reports; (iii) self-certifications; and (v) periodic data submittals. The Regional Entities' extensive compliance monitoring efforts, specifically with respect to compliance audits, spot checks, and self-reports, can be seen in Table 3.[92]

Compliance Monitoring Activities – Table 3									
		FRCC	**MRO**	**NPCC**	**RF**	**SERC**	**SPP RE**	**TRE**	**WECC**
Compliance Audits	2009	22	25	66	49	55	46	24	90
	2010	19	20	56	52	49	47	50	92
	2011	20	18	68	84	79	92	53	101
	2012	34	18	56	99	73	72	74	150
	2013	22	21	78	90	55	42	64	165
Total		**117**	**102**	**324**	**374**	**279**	**299**	**265**	**598**
Spot Checks	2009	40	64	40	147	45	90	1	8
	2010	12	27	51	57	24	14	53	32
	2011	61	8	30	30	11	17	45	16
	2012	5	1	120	3	0	6	43	0
	2013	5	0	483	2	0	3	12	6
Total		**123**	**100**	**724**	**239**	**80**	**130**	**154**	**62**
Self-Reports	2009	73	12	31	56	92	54	8	313
	2010	63	44	75	264	194	106	88	140
	2011	80	90	120	262	208	154	105	220
	2012	30	50	90	325	211	83	76	184
	2013	21	60	78	240	216	109	73	162
Total		**267**	**256**	**344**	**1,147**	**852**	**505**	**350**	**1,019**

The 2009 JRESA primarily focused on compliance audits, and the following discussion will be tailored accordingly. Importantly, during the assessment period, the Regional Entities completed the first three-year cycle of such audits for registered entities (registered in 2007 or 2008) performing the RC, BA, and TOP functions on schedule in 2010, and the six-year cycle for those registered entities not performing one of the three certified functions on schedule in 2013. Some Regional Entities also completed a portion of the second 3-year audits during the assessment period.

[92] The CMEP also once included Exception Reporting, which was removed by the revisions to the NERC ROP, approved by the Commission on December 20, 2012. *See* 141 FERC ¶ 61,241 (2102). The Regional Entities review self-certifications for all registered entities at least once annually. Some Regional Entities also require monthly self-certifications for certain Reliability Standards and Requirements. Periodic data submittals happen continuously, with certain information due to the Regional Entities on a monthly basis, other data on a quarterly basis.

The 2009 JRESA touched mainly on three topics related to Compliance Audits—the effectiveness of the RSAWs, the adequacy of audit training, and the status of NERC and FERC observers in regional audits. These will be taken up in turn.

Reliability Standards Audit Worksheets

As a general matter, the Regional Entities believe that RSAWs are helpful in their conduct of compliance audits. For example, they provide a means for recording the conduct of the audit, including detailed auditor notes and findings, and can be linked to the registered entity's evidence that can then be more easily reviewed. Registered entities appear to appreciate them, and use them extensively to prepare for an audit. Nevertheless, all of the Regional Entities believe that the RSAWs could be improved, and are pleased that their staffs are involved in the task force for that purpose. They are concerned, among other things, that the RSAWs attempt to meet multiple diverse needs, with the result being that no need is met fully or effectively; lack sufficient detail or granularity to be effective in guiding the conduct of the audit; constitute nothing more at times than a restatement of the requirement and provide little meaningful guidance to the auditor or the audited entity; and are generally cumbersome to use. As a consequence, some of the Regional Entities have developed alternate or supplemental tools to augment the RSAWs, e.g., with detailed data requests and inventory workbooks. Of course, in the Regional Entities' opinion, the audit process checklist and auditor handbook, described earlier, will help alleviate many of the Regional Entities' current concerns.

Adequacy of Audit Training

Without question, the Regional Entities are mindful of the importance of adequate audit training, both of their own staffs and for their registered entities. Accordingly, during the assessment period, they routinely encouraged, if not required, their staffs to attend or otherwise participate in relevant training sponsored by NERC (e.g., semi-annual ERO auditor workshops, GAGAS performance audit training, fundamentals of audits training, audit team leader training, compliance investigations training, *Crucial Conversations* training, and gathering quality evidence online training) or provided by third-party vendors; conducted their own in-house training; and regularly held compliance workshops for their registered entities.[93] In addition, they stressed the importance of their staffs continuing their education in specialized areas, such as cybersecurity, and maintaining or adding to their professional accreditations. As a result, the Regional Entities are confident that during the assessment period they assembled highly trained and professional audit staffs, which some of them supplemented with outside consultants with corresponding qualifications and credentials and with industry subject matter experts, to carry out their compliance monitoring obligations.[94]

[93] A good overview of NERC's training can be found in its filing submitted in compliance with the Commission's initial order on the FFT program in Docket No. RC11-6-003, on October 12, 2012, and accepted by Delegated Letter Order, on February 25, 2013.

[94] The Regional Entities' Cyber Infrastructure Protection auditor qualifications are discussed in greater detail below under §F.3, Additional Statutory Functions.

The Regional Entities will steadfastly continue these efforts, which complement and otherwise support the development of RAI. In this regard, the Third-Party Assessment suggested ways for improving auditor training, which are currently under active consideration by the ERO Enterprise. These suggestions include:

(1) Understanding and inventorying audit training over the past 2 to 3 years;

(2) Identifying initial pockets of excellence that could be leveraged;

(3) Preparing an initial listing and profile of known trainings and certifications that should be embedded within an on-going training program;

(4) Reconfirming and defining key trainings that include content related to auditing and understanding the technical aspects of the NERC requirements;

(5) Determining which professional certifications are best suited for audit professionals;

(6) Developing a program that includes all desired training and certifications;

(7) Assigning a target audience, delivery method, importance, approximate course length and frequency for each item in the training program;

(8) Establishing a method to track employee completion which will report data on progress per employee, office and region;

(9) Developing a process for proactive monitoring and continued improvements in the current training program;

(10) Creating individual annual training requirements for each employee based on gaps in their current skill sets and their expressed interests; and

(11) Tracking training and certification completion status and periodically reporting progress.

Status of NERC and FERC Observers in Regional Audits

The final compliance audit topic addressed in the 2009 JRESA concerned the uncertainty of the scope of participation by NERC and FERC observers in regional audits, even though as a general matter the Regional Entities found benefit in the observers' feedback. The Regional Entities believe that this uncertainty was largely resolved during the assessment period by Commission-approved changes to the NERC ROP Appendix 4C, §3.1.5.3, which clearly sets forth the role of audit observers, stating that "[c]ompliance Audit observers and attendees are not

Compliance Audit team members and do not participate in conducting the Compliance Audit or in making Compliance Audit findings and determinations."[95]

c. Enforcement

The 2009 JRESA touched on four specific enforcement-related topics in addition to issues of consistency—caseload backlog, treatment of minor violations, process transparency, and information management tools. As these topics overlap with each other and previously discussed topics, the following will combine the updates. As an initial matter, the Regional Entities want to stress that they continue to view communication and transparency in the enforcement process to be imperative to ensure a fair and effective implementation of the CMEP. They also believe that RAI is a positive step in that direction, and are committed to working with NERC and other members of the reliability community to make RAI a reality to advance BES reliability. In particular, RAI will support the goal of approaching the enforcement of the reliability standards on the basis of risk, as the initiative calls for evaluating registered entities' internal controls and processes, an evaluation that will enable the Regional Entities to create risk profiles. Once known, those risk profiles will assist the Regional Entities in both their compliance monitoring and enforcement activities, and eventually help reduce the time to final resolution of compliance issues.

The Regional Entities experienced a significant increase in the number of new violations discovered during the assessment period, in large part because of the introduction of the CIP mandatory Reliability Standards in 2010. Indeed, with the exception of the last year, NERC reported that the number of violations consistently trended upward during the assessment period, generally for all Regional Entities. This trend can be seen by Regional Entity on Table 4. NERC also reported that the CIP Reliability Standards were consistently the most frequently violated since 2010.[96]

New Violations during Assessment Period – Table 4						
	2009	**2010**	**2011**	**2012**	**2013**	**Total**
FRCC[97]	184	103	135	68	61	**551**
MRO	60	103	196	166	139	**664**
NPCC	43	99	130	213	66	**551**
RF	123	469	565	505	240	**1,902**
SERC	187	312	309	300	285	**1,393**
SPP RE	132	254	291	173	191	**1,041**
TRE	14	51	430	197	169	**861**

[95] *See* 141 FERC ¶ 61,241 (2012).

[96] *See* the PowerPoint presentation titled *Key Compliance and Enforcement Metrics and Trends* (February 2014), http://www.nerc.com/gov/bot/BOTCC/Compliance%20Committee%202013/Presentations%20--%20February%205,%202014.pdf, at slide 15.

[97] There is a slight difference between the FRCC number of violations in Table 4 and those found in NERC's assessment of the Regional Entities. FRCC's numbers here reflect the year in which the violations were discovered whereas the other numbers reflect the year the violations were reported to NERC.

New Violations during Assessment Period – Table 4						
	2009	**2010**	**2011**	**2012**	**2013**	**Total**
WECC	571	550	807	818	437	**3,183**
TOTALS	**1,314**	**1,941**	**2,863**	**2,440**	**1,588**	**10,146**

Notwithstanding the generally steady increase in new violations during the assessment period, the Regional Entities were able to meet their objectives, stated in the 2009 JRESA, to clear out what was described there as a backlog of violations, improve the time of processing violations (especially minor violations), and, generally speaking, establish stable workloads of enforcement cases. In particular, the Regional Entities' significant reduction in their pre-2012 caseload by the end of the assessment period can be seen on Table 5.[98]

[98] As NERC reported in its 2014 business plan and budget proposal:

> As of June 30, 2013, approximately 85% of the active non-CIP violations and 72% of the active CIP violations were discovered since January 1, 2012 (i.e., were discovered in the preceding 18 months). At June 30, 2013, there were no active non-CIP violations that were discovered prior to January 1, 2010 and only 12 active non-CIP violations that were discovered in 2010. There were only 16 active violations that were discovered in 2009 and 91 active CIP violations that were discovered in 2010. Further, for the 12 months ended June 30, 2013, the number of violations dismissed or filed with the Commission exceeded the number of new violations opened by 680 violations.

Request for Acceptance of 2013 Business Plans and Budgets of NERC and Regional Entities and for Approval of Proposed Assessments to Fund Budgets, Docket No. RR13-9-000 (submitted on August 23, 2013), at p. 104.

Reduction in Pre-2012 Violations Caseload – Table 5			
	Total violations open at the end of 2011	**Total violations open at the end of 2011 still open at end of 2013**	**Percentage of Reduction**
FRCC	95	0	100%
MRO	151	14	93%
NPCC	221	0	100%
RF	429	21[99]	95%
SERC	575	25	96%
SPP RE	233	6	97.4%
TRE	283	0[100]	100%
WECC	65	0	100%

The Regional Entities accomplished these objectives in the first instance by gaining more experience, expanding their enforcement staffs, increasing their outreach to registered entities, and focusing on improved efficiency. They also accomplished this by working with Commission staff, NERC, and the stakeholders in the development of the CEI, in particular the Administrative Citation NOPs, the SNOPs, and the FFTs.[101] As mentioned above, in 2012 and 2013, respectively, the use of SNOPs represented 48% and 43% of the total number of violations and possible violations submitted to the Commission. For the same years, the use of FFTs represented 38% and 43% of the total number of violations and possible violations processed by the Regional Entities.[102] Moreover, for violations and possible violations discovered after January 1, 2012 and filed by September 30, 2013, the average processing time for SNOPs and FFTs was 10.7 months and 7.4 months, respectively.[103] As the Commission can appreciate from the management of its own enforcement cases, as reported in its Enforcement staffs' annual reports, this represents a very respectable and acceptable time to process violations of the law.

[99] This number excludes Federal entity violations which are on hold due to legal issues.

[100] This number excludes one case involving two violations that is on appeal.

[101] The Regional Entities also credit the registered entities in the improvement in the processing of violations, namely that as they also gained experience through compliance and enforcement activities, they obtained a better understanding of how to comply with the standards and thereby were able to facilitate both activities.

[102] *See* the PowerPoint presentation titled *Key Compliance and Enforcement Metrics and Trends* (February 2014), http://www.nerc.com/gov/bot/BOTCC/Compliance%20Committee%202013/Presentations%20--%20February%205,%202014.pdf, at slide 10. For the period July 1, 2012 to June 28, 2013, this breaks down by region as follows:

	WECC	TRE	SPP RE	SERC	RF	NPCC	MRO	FRCC
FFT	25%	54%	44%	43%	41%	60%	57%	45%
SNOP	37%	23%	28%	38%	28%	39%	39%	40%
NOP	38%	23%	28%	19%	32%	1%	4%	15%

[103] *See* the PowerPoint presentation titled *Key Compliance and Enforcement Metrics and Trends* (November 2013), http://www.nerc.com/gov/bot/BOTCC/Compliance%20Committee%202013/CC_Presentations_Nov_2013_Complete.pdf, at slide 5.

At the same time as they were working to reduce their pre-2012 caseload and otherwise improve their processing of violations of the mandatory Reliability Standards, the Regional Entities endeavored to strictly oversee the completion of plans to mitigate those violations, because, axiomatically, timely mitigation is imperative for BPS reliability. Toward the end of the assessment period, they were able to improve the average times of two major milestones to less than a year, or significantly less than a year—the time from discovery of the violation to the registered entity's submittal of mitigation activities and the time from the discovery of a violation to the registered entity's completion of mitigation activities. This can be seen by Regional Entity for September 2012 through September 2013 in Table 6.

Average Times for Submittal and Completion of Mitigation Plans – Table 6		
	Average time from discovery of a violation to the registered entity's submittal of mitigating activities	**Average time from discovery of a violation to the registered entity's completion of mitigating activities**
FRCC	5.6 months	10.2 months
MRO	5 months	9 months
NPCC	3 months	3.4 months
RF	5.6 months	6.4 months
SERC	11 months	9 months
SPP RE	6.4 months	10.2 months
TRE	8 months	6 months
WECC	4.6 months	5.6 months

The Regional Entities achieved another 2009 enforcement goal during the assessment period by compiling and sharing with each other and the reliability community "lessons learned" from their enforcement proceedings. Accordingly, they were able to improve their own operations and help the registered entities to understand better how to comply with the mandatory Reliability Standards. They did this by: (i) creating webpages;[104] (ii) producing training videos; (iii) issuing newsletters with information on frequently violated standards and violation processing metrics;[105] (iv) publishing cases and dismissal notes;[106] (v) developing and sharing compliance guidance statements;[107] (vi) compiling other relevant written materials such as FAQs;[108] (vii) holding frequent compliance calls with registered entities; (viii) conducting

[104] *See*, e.g., http://www.texasre.org/StakeholderOutreach/LessonsLearned/Pages/Default.aspx; and http://www.serc1.org/Documents/Compliance/Statistics%20and%20Lessons%20Learned/2012/SERC%20Lessons%20Learned%20July%202012.pdf.

[105] *See*, e.g., https://rfirst.org/Pages/Newsletter.aspx.

[106] *See*, e.g., http://www.midwestreliability.org/02_compliance/Enforcement%20Case%20Notes/2013%20Case%20Notes/MRO%20Case%20Notes%202nd%20Quarter%202013.pdf.

[107] *See*, e.g., https://www.npcc.org/Compliance/Compliance%20Guidance%20Statements/Forms/Public%20List.aspx.

[108] *See*, e.g., https://www.frcc.com/FAQ/default.aspx.

numerous workshops, seminars, conferences, webinars, and open forums;[109] (ix) including detailed discussions in their compliance committee meetings; and (x) participating in trade and other industry conferences and conventions. Indeed, in the last three years of the assessment period (2011 through 2013), the Regional Entities' workshops and equivalent training programs attracted more than 30,000 attendees.[110]

Critical in the Regional Entities' enforcement activities is their use of information management tools. During the assessment period, they all changed or significantly improved or enhanced those tools. They did not, however, use the same tools (and there was no single, integrated compliance information system approach in place for them and NERC). Rather, they used one of two different integrated systems to manage compliance information received from registered entities. Five of the Regional Entities (RF, MRO, SPP RE, TRE, and WECC) used the web-based Compliance Data Management System (webCDMS), and three of the Regional Entities (SERC, NPCC, and FRCC) used the Compliance Issue Tracking System (CITS).[111] NERC used the Compliance Reporting and Tracking System (CRATS) to aggregate regional compliance data from webCDMS and CITS. While each system has its advantages, NERC and the Regional Entities plan to look to the feasibility of a common platform in the near future.

d. Hearings and Appeals

From the inception of the CMEP, the Regional Entities recognized the importance of providing sufficient process to registered entities which allegedly violated the mandatory Reliability Standards. Indeed, the Commission stressed more than once that the Regional Entities must have procedures in place to enable a registered entity to be heard in a trial-type hearing, and that NERC must have procedures in place to allow a registered entity to appeal a regional decision to the NERC Board and ultimately to the Commission.[112] Accordingly, the ERO Enterprise spent considerable time during the assessment period in developing and refining the *Hearing Procedures* laid out in Attachment 2 to NERC ROP Appendix 4C, and each Regional Entity issued its own CMEP hearing procedures, either incorporating or adopting by reference the procedures in Attachment 2. Many of the Regional Entities also provided training on the hearing procedures, including conducting a mock hearing, for their staffs, hearing bodies, or stakeholders.

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[109] *See*, e.g., http://www.wecc.biz/Training/Pages/default.aspx.

[110] This broke down by Regional Entity as follows: FRCC (2,176), MRO (1,219), NPCC (1,650), RF (1,260), SERC (4,019), SPP RE (2,451), TRE (2,924), and WECC (14,658). WECC had almost half of the attendees because it held routine open WebEx calls with pre-set agendas with the time dedicated for questions and answers.

[111] The Regional Entities also used a variety of other programs, such as SharePoint document management system and MK Insight materials repository system.

[112] *See*, e.g., *North American Electric Reliability Corporation, et al*., Order Accepting ERO Compliance Filing, Accepting ERO/Regional Entity Delegation Agreements, and Accepting Regional Entity 2007 Business Plans, 119 FERC ¶ 61,060 (2007), at PP 134-165*; North American Electric Reliability Corporation, et al.*, Order Addressing Revised Delegation Agreements, 122 FERC ¶ 61,245, at PP 74-138, *order on compliance filing*, 125 FERC ¶ 61,330 (2008), at PP 58-60.

Toward the end of the assessment period, with active participation by the Regional Entities, NERC proposed changes to *Hearing Procedures*, which the Commission approved on December 20, 2012.[113] Among other things, the Commission agreed with NERC's proposal to allow third-party interventions under a strict standard, namely that the intervener must have a direct and substantial interest in the outcome of the alleged violation, proposed penalty or sanction, mitigation plan, or remedial action directive.[114] The Regional Entities agree that the codification of this standard will facilitate the resolution of enforcement proceedings, especially in those regions with RTOs or ISOs, where a third-party may be allocated all or a portion of a penalty and where the Commission's objective of getting to the "root cause" of the violation is critical to such allocation.[115]

Even though all of the Regional Entities established hearing procedures and organized their resources to accommodate hearings, just three of them conducted a total of only five hearings during the assessment period.[116] RF conducted one regular hearing and one fast-tracked hearing, both of which were ultimately resolved by settlement. SPP RE conducted two regular hearings, one of which is pending resolution in the U.S. Court of Appeals for the D.C. Circuit,[117] and one for which a settlement was pending before the NERC Board of Trustees Compliance Committee as of December 31, 2013. TRE conducted one hearing, at the end of which its board of directors issued a confidential decision, in January 2013, and submitted the matter to the NERC Board where it was pending as of December 31, 2013. At this time, in light of the relatively little activity under the current ROP, the Regional Entities believe that they should

[113] *See North American Electric Reliability Corporation*, Order Conditionally Approving Revisions to North American Electric Reliability Corporation Rules of Procedure, 141 FERC ¶ 61,241 (2012), at PP 108-110.

[114] *Id*. P 110. *See also Monongahela Power Co., et al*., 135 FERC ¶ 61,226 (2011) (authorizing FirstEnergy to intervene in an RF hearing).

[115] *See generally Reliability Standard Compliance and Enforcement in Regions with Regional Transmission Organizations or Independent System Operators,* Order Providing Guidance on Recovery of Reliability Penalty Costs by Regional Transmission Organizations and Independent System Operators, 122 FERC ¶ 61,247 (2008); *see also PJM Interconnection, L.L.C.,* Order Accepting Tariff Revisions and Requiring Compliance Filing, 124 FERC ¶ 61,260 (2008) and *Midwest Independent Transmission Operator, Inc.,* Order Conditionally Accepting Proposed Tariff Revisions, 128 FERC ¶ 61,229 (2009).

[116] The Regional Entities also received very few complaints and conducted very few investigations (as that term is defined in the CMEP) during the assessment period as follows:

	FRCC	MRO	NPCC	RF	SERC	SPP RE	TRE	WECC
Complaints	2	1	6	4	4	1	3	0
Investigations	0	3	3	3	3	3	3*	1

*One of TRE's investigations involved a 2011 winter event that led to a FERC/NERC staff report, *Report on Outages and Curtailments During the Southwest Cold Weather Event on February 1-5, 2011*. *See* http://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf.

[117] *See Southwestern Power Administration, et al. v. FERC*, No. 13-1033 (D.C. Cir. Feb. 15, 2013).

obtain more experience with hearings and appeals before any significant changes are made to Attachment 2.[118]

3. Additional Statutory Functions

The 2009 JRESA identified four other functions which are primarily the ERO's responsibility but which require the active involvement, cooperation, and assistance of the Regional Entities—Reliability Assessment, Event Analysis, Situation Awareness, and Critical Infrastructure Protection.[119] In regard to Reliability Assessment, Event Analysis, and Situation Awareness, NERC and some industry members expressed concerns about the Regional Entities' performance. In regard to Critical Infrastructure Protection, the Regional Entities noted a concern they had. As now demonstrated, during the assessment period, the Regional Entities successfully took steps to address and otherwise allay the concerns of NERC and the industry members, and had its own concern satisfactorily addressed as well.[120]

a. Reliability Assessment

FPA §215(g), 16 U.S.C. §824o(g), provides that "[t[he ERO shall conduct periodic assessments of the reliability and adequacy of the bulk-power system in North America." Section 39.11 of the Commission's regulations, 18 C.F.R. §39.11 (2013), additionally directs the ERO to conduct such assessments and provide reports to the Commission and other designated entities. Accordingly, NERC prepares the annual *Long-Term Reliability Assessment*, *Summer Assessment*, *Winter Assessment*, and special assessments as needed. To this end, as can be gleaned from the NERC's *Reliability Assessment Guidebook* (version 3.1), NERC relies heavily on the Regional Entities to prepare these reports.[121] Indeed, as anticipated in the 2009 JRESA, the finalization of this guidebook during the assessment period adequately responded to the issues raised during the preparation of the Regional Entities' first performance assessment.[122] Nonetheless, the Regional Entities are committed to continue working with NERC to improve data collection and validation, and to foster greater alignment across the regions in the conduct of high quality, timely, and independent assessments that support the ERO Enterprise's valuation of reliability.

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[118] Notably, the Commission approved a major change to the TRE hearing procedures in August 2013, allowing TRE to change its hearing process, which previously provided for the Texas Public Utility Commission to serve as the hearing body, to be the same as used by the other seven Regional Entities. *See North American Electric Reliability Corporation*, Docket No. RR13-7-000 (August 19, 2013) (unpublished delegated letter order).

[119] *See* 2009 JRESA, at pp. 32-33.

[120] Additionally, as budget matters were discussed at various places in the 2009 JRESA, this section concludes with a brief overview of Regional business plans and budget activities during the assessment period.

[121] *See* http://www.nerc.com/pa/RAPA/rg/ReliabilityGuidelines/Reliability_Assess_Guidebook_3_1Final.pdf.

[122] Concerns at that time included data checking and validation, process and procedures, stakeholder/member involvement, and overall quality and timeliness.

b. Event Analysis

In the 2009 JRESA, the Regional Entities agreed with industry members that work needed to be done on the process of timely conducting, and disseminating information gathered from, event analyses performed by NERC and the Regional Entities.[123] Without question, the ERO Enterprise made tremendous strides during assessment period to address these concerns and otherwise improve the very critical reliability function of analyzing events and distributing lessons learned to the entire reliability community. For their part, the Regional Entities significantly contributed to this effort by helping to organize and actively participating in the voluntary ERO event analysis program.

By way of background, following the creation of the NERC Event Analysis Working Group (EAWG) and two industry trials in 2010, NERC approved an industry-wide event analysis program in February 2012, and revised it in 2013.[124] This voluntary program recognizes the need to establish an appropriate level of review for the events which occur on the BPS based on their varying levels of significance, while still providing otherwise unrealized lessons to be learned from both major and minor occurrences. To complete this effort, the registered entity, the Regional Entity, and NERC staff collaborate to prepare an event analysis report, identify root cause and contributing causes, perform a formal "cause-coding" analysis, and publish lessons learned gathered from the disturbance. The process also encourages registered entities to establish a liaison between their internal event analysis and compliance functions for development of a registered entity compliance self-assessment report separate from the event analysis report. During the assessment period, this integration of industry engagement and the collaborative review of disturbances greatly improved the effectiveness, consistency, and timeliness of event analyses performed by NERC and the Regional Entities.

The following shows the progress made by the voluntary ERO event analysis program, developed by NERC, the Regional Entities, and stakeholders. Between October 2010 and December 31, 2013, registered entities submitted 469 event reports through the program, two-thirds of which were classified as Category 1.[125] Generally, the registered entities were very

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[123] The *Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011, Causes and Recommendations* (August 2011) (2011 Southwest Cold Weather Event) neatly summarizes the event analysis process:

> Registered entities are required to report the occurrence of defined bulk power system disturbances and unusual occurrences to the appropriate Regional Entity and to NERC. The Regional Entity and/or NERC in turn undertakes various levels of analysis to determine the causes of the events, assure tracking of corrective actions to prevent recurrence, gather information needed to assess compliance, and provide lessons learned to the industry. The event analysis process also provides input for training and education, reliability trend analysis efforts and Reliability Standards development, all of which support continued reliability improvement.

http://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf, at p. 23.

[124] *See* http://www.nerc.com/pa/rrm/ea/EA%20Program%20Document%20Library/Final_ERO_EA_Process_V2.1.pdf. The EAWG eventually transitioned to the NERC Event Analysis Subcommittee.

[125] A Category 1 event includes, among other things, an unexpected outage, contrary to design, of three or more BPS elements caused by a common disturbance. *See* generally *Electric Reliability Organization Event Analysis Process*,

supportive of the process and worked with the Regional Entities' staffs to improve the quality of the reports, even providing subject matter experts to participate in calls to ensure that the reports were completely understood to more effectively assign categories and cause codes. The Regional Entities' staffs, in turn, were fully committed to the success of the lessons learned aspect of the program, and attempted to keep the registered entities up to date on the program and to help develop meaningful lessons learned. As is well known, during the assessment period, the two most notable event analyses were performed by NERC and FERC staffs with respect to the 2011 Southwest Cold Weather Event and the 2011 Arizona-Southern California Outages.[126] In both matters, the reports provided valuable information and recommendations that were closely examined by the other Regional Entities for application in their areas.[127]

c. Situation Awareness

The 2009 JRESA touched briefly on situation awareness, and took note that NERC and the Regional Entities were actively participating with FERC to enhance situation awareness by having RCs provide near-real-time operating information for their respective footprints to the Commission, NERC and the Regional Entities in order to permit the Commission to "measure the health" of the Interconnections and to monitor parameters which might warn of a developing crisis. The Regional Entities cautioned in 2009 that the communication protocols should be followed in order to prevent this effort from exposing system operators to distracting inquiries during emergency situations. Since then, as now explained, the efforts underway in 2009 were largely successful and the Regional Entities' concerns were satisfactorily addressed.

During the assessment period, FERC, NERC, and Regional Entity staffs worked together to develop a near-real time situation awareness visualization tool called SAFNR (**S**ituation **A**wareness for **F**ERC, **N**ERC, and the **R**egional Entities). SAFNR version 1 was implemented in June 2009. SAFNR version 2, which provides enhanced situation awareness with increased

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Appendix E: Categorization of Events (February 2012) at http://www.nerc.com/pa/rrm/ea/EA%20Program%20Document%20Library/ERO_Event_Analysis_Process_Document_Version_1_Feb_2012.pdf. There was only one Category 5 event during the assessment period—Hurricane Sandy in 2012.

The events covered by the reports break down by Regional Entity as follows:

FRCC	MRO	NPCC	RF	SERC	SPP RE	TRE	WECC
25	41	69	47	42	13	69	163

[126] *See* n. 125 and *Arizona-Southern California Outages on September 8, 2011, Causes and Recommendation*s (April 2012) (2011 Arizona-Southern California Outages) http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf. *See also Arizona Public Service Company*, Order Approving Stipulation and Consent Agreement, 148 FERC ¶ 61,009 (2014) (approving first settlement in 2011 Southwest Blackout case between FERC's Office of Enforcement, NERC, and Arizona Public Service Company).

[127] For example, in light of the recommendations in the Arizona-Southern California Outages report, SPP RE staff conducted a survey of entities regarding operational planning and real-time situational awareness, and worked with the SPP RTO and the SPP Event Analysis Working Group to craft training materials. In addition, the SPP RTO implemented a daily benchmark process of the "next day" models to validate load forecasting and generation dispatch assumptions as well as voltage performance. Also in consideration of the recommendations in that report, WECC launched an initiative to improve modeling of remedial action schemes and relays.

trending capability, was completed in late 2012. As contemplated in the 2009 JRESA, SAFNR calls for U.S. RCs to provide system conditions via the internet to FERC, NERC, and the Regional Entities thereby allowing them to monitor continuously operating conditions and emerging reliability events on the BPS. In addition to the near-real time monitoring capabilities of SAFNR, the RCs send situation awareness reports every morning to the Commission, NERC, and the Regional Entities. These reports include an overview of weather conditions, transmission line and generation outages, and operating reserves. Furthermore, the Regional Entities participate in weekly situation awareness and event analysis conference calls with NERC. From the Regional Entities' perspective, the combination of SAFNR, the daily situation awareness reports, and the weekly calls with the ERO, give them a good overview of what is happening on the BES. And, of course, they are in regular communication with the registered entities within their footprints, in particular the RCs, and provide those entities with the means to contact them or receive pertinent information from them at all times with respect to any incidents or events on the grid.[128]

d. Critical Infrastructure Protection

The 2009 JRESA posited only one issue with respect to CIP, namely that the Commission should approve a pending proposal to amend the NERC ROP to provide that any Technical Feasibility Exception (TFE) requests (from the coverage of the CIP Reliability Standards) be submitted in the first instance to the Regional Entities, rather than to NERC.[129] Early in the assessment period, the Commission approved the proposed amendment, thus mooting the issue raised in 2009.[130] More recently, in September 2013, the Commission approved what NERC described as the first comprehensive review of the TFE process since it was originally developed and approved.[131] The Commission explained that NERC and the Regional Entities had processed by that time over 3,800 TFE requests in the past three years, including over 1,300 TFE requests in 2011, experience that supported NERC's proposal to streamline the process for submitting, reviewing, and approving or disapproving TFE requests, and for modifying approved TFEs.[132] The Regional Entities are pleased that the Commission

[128] For example, WECC established a web portal to allow BAs and TOPs access to actual RC real-time state estimator, contingency analysis, and other situational awareness-enhancing tools. NPCC introduced the *Emergency Preparedness Conference Call Procedures* to enable the RCs in its footprint, and, as circumstances may require, their counterparts in neighboring Regional Entities, to rapidly communicate the status of current operating conditions, facilitate the procurement of assistance during emergency conditions, and identify potential physical or cyber threats to the system.

[129] TFE requests primarily arise with respect to long-life equipment in place that is not readily compatible with a modern environment where cyber security issues are a concern. *See Mandatory Reliability Standards for Critical Infrastructure Protection*, Order No. 706, 122 FERC ¶ 61,040 (2008), at P 180.

[130] *See North American Electric Reliability Corporation*, Order Approving Technical Feasibility Exception Procedures and Ordering Compliance Filing, 130 FERC ¶ 61,050 (2010).

[131] *See North American Electric Reliability Corporation,* Order Approving Revisions to Electric Reliability Organization's Rules of Procedure and Directing Compliance Filing, 144 FERC ¶ 61,180 (2013), *order on compliance*, Docket No. RR13-3-001 (January 30, 2014) (unpublished letter order).

[132] *Id.* P 12.

approved NERC's proposed amendments, which will help reduce TFE processing times while maintaining the integrity of the CIP mandatory Reliability Standards.

In addition, during the assessment period, the Regional Entities significantly expanded the number and the expertise of their staffs, in particular their auditors, to verify compliance with the CIP mandatory Reliability Standards. They uniformly hired personnel with relevant credentials and experience. For example, SPP RE's audit team (as of mid-2013) had over 94 years of information technology, cybersecurity, and IT audit experience, including 52 years of experience in the electricity sector, and FRCC required (as of mid-2013), as a condition of employment, five years of experience in cybersecurity practices, information technology, auditing practices, implementation of NERC Reliability Standards, or other equivalent experience. Moreover, by the end of the assessment period, many of the Regional Entities' employees held active certifications recognized by the U.S. Department of Defense Directive 8570 (e.g., Certified Information Systems Auditor (CISA), Certified Information Systems Security Specialists (CISSP), Certified Ethical Hacker (CEH), and Network +). They also sought out personnel who understood energy management systems (EMS) and supervisory control and data acquisition (SCADA) systems and several of them augmented their staffs' expertise with contractors who held similar credentials and experience.

Needless to say, the Regional Entities recognize the incredibly important role that cybersecurity plays in the fulfillment of their statutory responsibilities.[133] Accordingly, during the assessment period, they uniformly expended considerable resources and effort to organize their CIP programs and to enforce the mandatory CIP Reliability Standards. Several also initiated on-site visits at their registered entities to assess their physical security, to discuss with those entities the intricacies of complying with the CIP Reliability Standards, and to explore best industry practices with respect to cybersecurity. In addition, the Regional Entities improved their own technology to be able to handle the transport and storage of the especially sensitive information that they collect in CIP compliance audits and investigations.

Finally, during the assessment period, Regional Entities participated in two NERC Grid Security Exercises (GridEx), which use best practices from the Department of Homeland Security, the Federal Emergency Management Agency, and the National Institute of Standards and Technology. Six Regional Entities (MRO, NPCC, RF, SERC, TRE, and WECC) joined 70 industry and government organizations in the 2011 GridEx, on November 16, 2011 through November 17, 2011, and six Regional Entities (FRCC, MRO, NPCC, RF, SERC, and TRE) joined more than 200 industry and government organizations, either as full participants or as observers, in the 2013 GridEx on November 13, 2013 through November 14, 2013. The 2011 GridEx was designed to validate the readiness of the Electricity Sub-sector to respond to a cybersecurity incident, strengthen registered entities' crisis response functions, and provide input for internal security program improvements. Overall, the exercise was widely regarded across industry and government as a critical imperative in preparing the BPS for a disruptive cyber event.[134] The 2013 GridEx gave participants the opportunity to check the readiness of their crisis

[133] *See* 16 U.S.C. §§824o(a)(3) and (4).

[134] *See 2011 NERC Grid Security Exercise After Action Report* (March 2012) at http://www.nerc.com/pa/CI/CIPOutreach/Documents/NERC%20GridEx%20AAR%2016Mar2012%20Final.pdf.

action plans through a simulated security exercise to self-assess response and recovery capabilities, and to adjust actions and plans as needed, while communicating with industry and government information sharing organizations.[135]

4. Budget

The 2009 JRESA mentioned various budget matters but did not include a separate section on the topic. The significant progress made in this area during the assessment period by the Regional Entities under NERC leadership calls for at least a brief discussion here. Also, as related generally in the Introduction and specifically by each Regional Entity in Appendix C, the Regional Entities are required by FPA §215 to establish rules that "allocate equitably reasonable dues, fees, and other charges among end users for all activities," an obligation that obviously necessitates that they function under a business plan and a budget. The Regional Entities first approached these budget responsibilities during the assessment period by developing, in collaboration with NERC, and proposing annual business plans and budgets, in accordance with Commission orders, ERO rules, and NERC business planning and budgeting policies and instructions. For this purpose, they used NERC forms for business plan and budget submittal and adhered to NERC's schedule for preparation of the business plan and budget and related financial statements. They likewise followed NERC's prescribed system of accounts (except to the extent that NERC permitted a departure from the prescribed system of accounts).

The Regional Entities made significant progress in the development and submission of their annual business plans and budgets partly as a result of their active participation in the Regional Entity Budget Group (REBG), which transitioned during the assessment period to the ERO Finance Group (EROFG). This group reviewed templates, budget processes, schedules and deadlines, account classifications, financial reporting, and accounting changes. Members of the group were able to share information concerning benefits, salaries, policies, and procedures that are used in the day-to-day accounting activities in the regions. The Regional Entities also took advantage of the opportunity to preview their preliminary annual budgets for Commission staff, and receive feedback generally and with respect to staffing needs and extraordinary items. They further worked with NERC to develop long term resource and financial planning, and to formulate a set of "common assumptions," which helped to clarify expectations. As a consequence of the concerted efforts made by NERC, the Regional Entities, and the EROFG, the regional budget process significantly improved during the assessment period, progressing from a level of some uncertainty to a level of considerable predictability regarding needed resources and anticipated expenses.[136]

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[135] *See Grid Security Exercise (GridExII) After-Action Report* (March 2014) available at: http://www.nerc.com/pa/CI/CIPOutreach/GridEX/GridEx%20II%20After%20Action%20Report.pdf. The Regional Entities were also represented at the "tabletop" of executives from government, industry, and NERC, which took place after the 2013 exercise.

[136] An excellent overview of the progress made by the ERO Enterprise during the last year of the assessment period in preparing the Regional Entities' 2014 business plans and budgets can be found in NERC's *Request for Acceptance of 2014 Business Plans and Budgets of NERC and Regional Entities and for Approval of Proposed Assessments to Fund Budgets*, Docket No. RR13-9-000 (submitted on August 23, 2013), at pp. 24-30. *See also*

CONCLUSION

The ERO Enterprise significantly matured during the assessment period, building on the foundation of the first three years of the program in which the ERO and the Regional Entities had to set up and organize their operations to implement a sweeping new set of Federal laws, regulations, policies and practices under the oversight of the Commission. Those first three years were truly a time of learning and adjusting to the new paradigm. The next five years, the current assessment period, were a time to learn from experience and explore ways to improve, refine, and stabilize the program. The Regional Entities successfully contributed to those objectives in several ways. They worked more closely and productively with the ERO and with each other. They reached out to and trained their registered entities and other stakeholders. They actively participated in FERC proceedings to keep the Commission informed and to help craft orders and policies that appropriately advance reliability. They continuously examined ways to be more efficient and effective in exercising their compliance enforcement authority and to better gauge the risk that noncompliance posed to reliability. Finally, at all times, they met their statutory obligations to be impartial, develop reasonable and technically sound standards, enforce those standards with due process, operate within sound business plans and budgets, coordinate their efforts in North America, where applicable, and function under RDAs that promote effective and efficient administration of BPS reliability.

North American Electric Reliability Corporation, Order on 2014 Business Plan and Budget of the North American Electric Reliability Corporation and Ordering Compliance Filing, 145 FERC ¶ 61,097 (2013).

Appendix A
Description of Regional Entities

A Regional Entity is an organization that has been delegated certain statutory functions of the Electric Reliability Organization (ERO). The ERO and each Regional Entity consummate the delegation through the execution of a Delegation Agreement, which must be approved by the Federal Energy Regulatory Commission (Commission or FERC) in the U.S. By entering into such an agreement, the Regional Entity becomes subject to the jurisdiction of the FERC and the rules of procedure of the ERO.

In July 2006, when the Commission certified the North American Electric Reliability Corporation (NERC) as the ERO, it also accepted NERC's proposal to delegate certain ERO functions to designated Regional Entities, as well as NERC's proposed *pro forma* Delegation Agreement.[137] In April 2007, NERC entered into separate Delegation Agreements with eight Regional Entities, through which NERC delegated certain ERO functions. Specifically, NERC delegated authority to the Regional Entities to audit, investigate, and otherwise ensure that users, owners, and operators of the BPS comply with NERC's mandatory Reliability Standards, subject to ERO oversight.[138] Further, the Delegation Agreements addressed: (i) Regional Reliability Standards development; (ii) registration of entities that must comply with Reliability Standards; and (iii) other services supporting NERC's functions, including reliability assessments, event analysis, and training and education. In October 2010, the Commission approved a revised *pro forma* Delegation Agreement, and revised Delegation Agreements between NERC and each of the eight Regional Entities.[139] Subsequently, the Commission also approved other changes to specific Delegation Agreements.[140]

As shown in Figure 1, the existing eight Regional Entities provide full geographic coverage for the jurisdictional scope of NERC as the international ERO.

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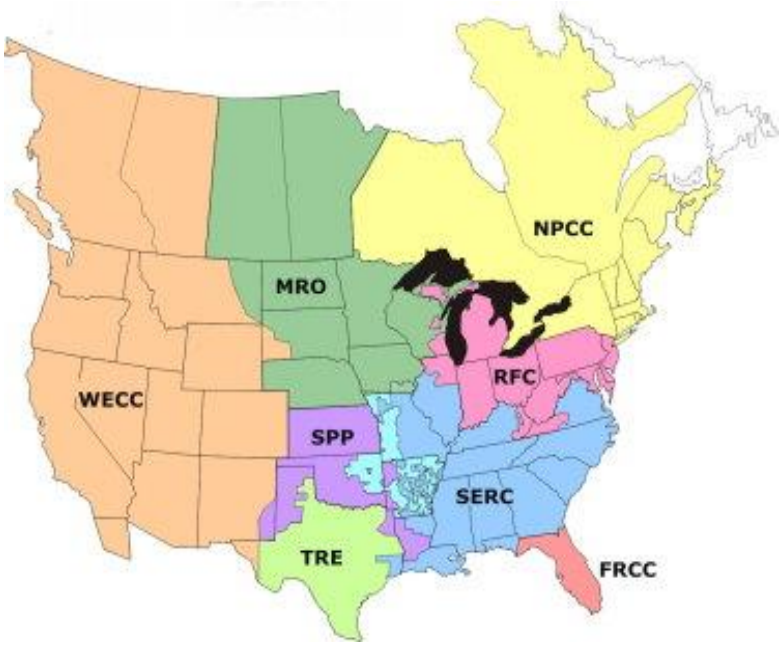
[137] *See North American Electric Reliability Corporation*, Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing, 116 FERC ¶ 61,062, *order on reh'g*, 117 FERC ¶ 61,126 (2006).

[138] *See North American Electric Reliability Corp.*, 119 FERC ¶ 61,060, *order on reh'g,* 120 FERC ¶ 61,260 (2007).

[139] *See North American Electric Reliability Corporation*, 133 FERC ¶ 61,061 (2010), *order on reh'g*, 134 FERC ¶ 61,179, *order on compliance filing*, 137 FERC ¶ 61,028 (2011).

[140] *See*, e.g. *North American Electric Reliability Corporation*, Docket Nos. RR13-7-000 (Aug. 19, 2013) (TRE), RR13-5-000 (June 12, 2013) (MRO), RR12-12-000 (Oct. 24, 2012) (RF), RR12-4-000 (June 12, 2012) (FRCC), and RR12-2-000 (March 1, 2012) (WECC) (unpublished delegated letter orders).

Figure 1 — Map of Regional Entities within NERC



Each of the Regional Entities is briefly described below.

Florida Reliability Coordinating Council, Inc. (FRCC) was formed in 1996. Its sole purpose is to ensure and enhance the reliability and adequacy of the BPS in Florida. Since becoming a Regional Entity, FRCC has made significant changes in its governance and organizational structure. FRCC amended its bylaws to create two membership divisions — Regional Entity Division (statutory functions) and Member Services Division (non-statutory functions), added a new General Sector to its membership sectors, added new employees strictly dedicated to the compliance and standards functions, and made changes in its organizational reporting structure. All staff members are independent of registered entities, and the organization is governed by a balanced stakeholder board. FRCC has also implemented internal controls in its accounting procedures to ensure there is no cross subsidization of funds between statutory and non-statutory activities.

Midwest Reliability Organization (MRO) was formed from the former Mid-Continent Area Power Pool (MAPP) Regional council and a portion of Mid-America Interpool Network (MAIN) as a new corporation for the purpose of becoming a Regional Entity under the Energy Policy Act of 2005 and the Bilateral Principles. The region spans eight states and two Canadian provinces. MRO's bylaws provide for members from the following industry sectors: municipal utilities, cooperatives, investor-owned utilities, federal power marketing agency, Canadian Crown Corporations, and independent power producers. MRO's bylaws also allow for adjunct members that are not eligible to belong to an industry sector and have a material interest in reliability issues in the MRO region. Membership is at no cost. MRO is independent of all BPS owners, operators, and users, and has no shared employees with any third party. MRO performs only responsibilities delegated from the ERO and similar functions in the Canadian provinces of Saskatchewan and Manitoba. MRO's board of directors (MRO Board) represents a hybrid

governance structure with both independent and stakeholder directors. The stakeholder directors represent the industry sectors noted above; two independent directors are elected by the entire membership. MRO's hybrid board is structured so that no two sectors can control a vote. The MRO Board has adopted procedures to ensure that it carries out its responsibilities in a non-discriminatory manner, free of conflicts.

Northeast Power Coordinating Council, Inc. (NPCC) was established as the voluntary, international regional reliability organization for Northeastern North America in January 1966. NPCC is a not-for-profit corporation with a Regional Entity division that performs the statutory functions delegated by NERC and a Criteria Services division that establishes, monitors, and enforces compliance with regionally-specific criteria. The NPCC geographic region includes the State of New York and the six New England states as well as the Canadian provinces of Ontario, Québec and the Maritime provinces of New Brunswick and Nova Scotia. Overall, NPCC covers an area of nearly 1.2 million square miles, populated by more than 55 million people. In total, from a NEL perspective, NPCC is approximately 45% U.S. and 55% Canadian. With regard to Canada, approximately 70% of Canadian NEL is within the NPCC region. NPCC's board of directors consists of seven stakeholder voting sectors that each consist of a maximum of two directors per sector, an independent sector consisting of two independent directors, an independent board chair with voting rights to preclude board deadlocks, and the President and CEO. Within NPCC, no two sectors can control and no one sector can block action.

ReliabilityFirst Corporation (RF) was formed from parts of the former East Central Area Reliability Council (ECAR), MAIN, and the Mid-Atlantic Area Council (MAAC) Regional reliability councils on January 1, 2006. The organization was specifically designed to address changes required by the Energy Policy Act of 2005 and to support the ERO in a self-regulating model by which the industry participants establish their own standards and independent Regional Entities determine compliance to those standards. The organization was modified from top to bottom compared to the legacy reliability councils it replaced, and exists solely to serve as a FERC-approved Regional Entity performing only those functions delegated to it by NERC as the ERO. All ReliabilityFirst staff are independent of registered entities, the organization is governed by a hybrid board of directors, which includes both independent and balanced industry sector directors, and the organization is funded (through the ERO) by all load-serving entities in the footprint as opposed to members (membership is free.)

SERC Reliability Corporation (SERC) was incorporated in April 2005, replacing the Regional reliability council previously in existence since 1969. The new organization was redesigned to meet FPA §215 and FERC criteria for delegating statutory authorities and responsibilities. SERC's scope includes only statutory functions delegated by NERC. The organization does not perform any registered entity functions and has no business affiliations with any registered entities. SERC adopted new bylaws, approved by FERC in April 2007, that provide for a balanced stakeholder board with seven sectors. All SERC staff are independent of registered entities. The organization is funded through the ERO. Membership is free and open to all owners, operators, and users in the SERC region.

Southwest Power Pool Regional Entity (SPP RE) has made fundamental governance and organizational changes necessary to carry out its delegated responsibilities. In response to

the Energy Policy Act of 2005, Southwest Power Pool, Inc. (SPP), created a new department to perform all compliance activities over SPP registered entities. SPP RE began engaging NERC to lead SPP audits in 2007. In April 2007, FERC approved changes to the SPP bylaws creating three independent trustees to manage all SPP RE delegated activities. These trustees, initially elected in June 2007, are required to be independent of SPP members and customers, and registered entities in the region. In March 2009, SPP RE hired a general manager, reporting directly to the three independent trustees, to oversee the execution of the Regional Entity strategic direction and direct the day-to-day operations, including all compliance and enforcement activities. The general manager oversees only delegated statutory functions. All reporting relationships between SPP RE employees and SPP employees have been terminated.

Texas Reliability Entity, Inc. (Texas RE or TRE) is a non-profit Texas corporation that was formed to serve as the Regional Entity for the Electric Reliability Council of Texas, Inc. (ERCOT) region, and to preserve and enhance reliability in the region. Effective July 1, 2010, Texas RE took over the duties of the previous Regional Entity, the Texas Regional Entity, an independent division of ERCOT. Texas RE also performs non-statutory activities as the Reliability Monitor for the ERCOT region pursuant to its July 1, 2010, agreement with the Public Utility Commission of Texas (PUCT) and ERCOT (the ISO in the region). As Reliability Monitor, Texas RE monitors and reports to the PUCT regarding market participants' compliance with electric reliability-related ERCOT Protocols, Operating Guides, and Texas rules (ERCOT Regional Rules). The ERCOT region is the geographic area located within the state of Texas that operates under the jurisdiction of the PUCT and is not synchronously interconnected with any electric utilities operating outside of Texas. The ERCOT region includes approximately 85 percent of Texas load and 75 percent of the Texas land area.

Western Electricity Coordinating Council (WECC) is the successor to the Western Systems Coordinating Council (WSCC), which was formed in 1967. WECC, established in April 2002, continues to be responsible for promoting and coordinating electric system reliability among industry stakeholders as had been done by WSCC since its formation. On July 20, 2006, pursuant to FPA §215, NERC was certified as the ERO in the U.S. Included in this certification was a provision for the ERO to delegate authority for the creation and enforcement reliability to Regional Entities such as WECC. WECC is geographically the largest and most diverse of the eight Regional Entities that have Delegation Agreements with NERC. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 Western states between. Due to the size and diverse characteristics of the region, WECC and its members face unique challenges in coordinating the day-to-day interconnected system operation and the long-range planning needed to provide reliable electric service across nearly 1.8 million square miles. Membership in WECC is open to all entities with an interest in the operation of the BPS in the Western Interconnection. All meetings are open and anyone may participate in WECC's standards development process.

On June 27, 2013, the WECC board of directors (WECC Board) approved the bifurcation of the company into a Regional Entity (WECC) and a Reliability Coordination Company (Peak Reliability). This decision—which is the culmination of a year of work by various WECC board committees, staff, WECC members, and WECC stakeholders—signals a major landmark in the

history of the organization. Under this new structure the reliability coordinator and interchange authority functions in the Western Interconnection became a separate company from WECC. When established, Peak Reliability will provide core and other associated reliability coordination services within the Western Interconnection. As anticipated, the Commission approved the relevant documents by the end of December 2013; however, as there were outstanding compliance filings, the bifurcation was not finalized during the assessment period. Nevertheless, WECC and Peak Reliability began operating as separate entities in many respects by that time.

Appendix B
Regional Entity Responses to Specific Concerns Raised in the Commission's September 16, 2010 Order on the Three-Year ERO Performance Assessment

In the order on the Electric Reliability Organization's Three-Year Performance Assessment (2010 Order), the Commission discussed several specific concerns regarding Regional Entity activities including: (i) compliance monitoring and enforcement issues concerning all Regional Entities; (ii) NERC's evaluation of each Regional Entity compliance program; (iii) SPP independence; and (iv) WECC's voting structure.[141] The first topic has been addressed throughout the 2014 JRESA. The other three region-specific topics are addressed below (italicized paragraphs come from the 2010 Order).

NERC's Evaluation of Each Regional Entity

222. *With respect to **FRCC**, NERC states that FRCC needs to improve its timeliness in: (1) reporting alleged violations to NERC; (2) issuing notices of alleged violation; (3) confirming violations and issuing notices of confirmed violation or entering into settlement agreements; and (4) obtaining Board of Trustees Compliance Committee approval of confirmed violations. NERC relates that FRCC recently has increased its compliance program staffing and, as of the Performance Assessment filing date, had the second lowest number of registered functions per full-time equivalent (FTE) committed to compliance of any Regional Entity.*

The FRCC improved its timeliness in all aspects of the compliance and enforcement processes during the assessment period. Notices of alleged violations, notices of confirmed violations and settlements were handled by the FRCC Compliance Enforcement staff. In January 2010, FRCC created a new position of manager of compliance enforcement, promoted a senior auditor to that position, and added two new enforcement positions, an enforcement specialist and a compliance legal assistant. The enforcement specialist position was filled in January 2010, and the legal assistant was filled in May 2010. Subsequently, the FRCC added two more enforcement positions, both CIP enforcement specialists. With the increased enforcement staff, the FRCC worked steadily to improve all of its processes. Additionally, FRCC developed internal processes and goals to support and facilitate the processing of alleged violations, as follows:

- Created enforcement processing checklists;
- Developed violation and mitigation plan responsibility flowcharts;
- Developed enforcement procedures;
- Created annual success plan goals for enforcement team members;
- Implemented departmental caseload goal;
- Developed internal enforcement processing metrics;
- Collaborated with other Regional Entities in a Consortium Users Group (CUG) to improve data base management tool;
- Automated database reporting tools which improved efficiency;

[141] *North American Electric Reliability Corporation, et al*., 132 FERC ¶ 61,217 (2010) at PP 198-244.

- Implemented a secure vault system for registered entity CIP data, which eliminated onsite reviews; and
- Compiled with NERC requests to complete processing of all violations through 2011 to NERC goals.

223. *NERC views **MRO** as an effective Regional Entity. NERC indicates that MRO should improve by providing accurate statements of fact for each violation and assess penalties according to the facts of each situation. NERC has concerns about several of MRO's compliance processes, which NERC has not yet reviewed or approved. NERC states that although these methods may be effective, they are not consistent with NERC practices and could lead to inconsistency with other regions.*

NERC's 2009 assessment alluded to two situations which occurred in that year. The first involved the issuance by FERC of a formal notice extending the time for consideration of a NOP (NP09-21-000), in which FERC requested additional information and clarification of certain facts. While MRO was the first of the Regional Entities to receive such a formal notice, similar notices were subsequently issued to all of the Regional Entities. In some instances, the Commission issued multiple requests to the same region. In only one instance, during the assessment period, did the Commission undertake its own review of a regional enforcement determination (WECC decision in Turlock, FERC Docket No. NP10-18-000), which was ultimately affirmed. MRO has not received any other formal requests from FERC for additional information and clarification.

Also in 2009, the NERC BOTCC remanded an enforcement action because MRO characterized a self-certification as a self-report in its determination. This was a simple administrative error, which MRO appreciates being found by NERC. Subsequently, MRO worked with NERC staff to develop a process whereby NERC staff works with Regional Entity staff to ensure agreement with or clarification of discrepancies prior to presenting enforcement actions to the BOTCC for approval. At the time, the MRO self-certification process was a manual process, which then required MRO compliance staff to enter the information into the data management system (CDMS). In this instance, MRO compliance staff entered the self-certification into the CDMS application as a self-report without indicating that the possible violation was actually identified through the self-certification process. This was the only instance where such an error occurred and it did not change the enforcement determination.

Finally, MRO believes that NERC's concerns about several of MRO's compliance processes, which NERC stated may be effective, were due to NERC's misunderstanding MRO's practices at the time. Shortly before the submission of the 2009 JRESA, MRO adopted its three-step process for activities within the CMEP: (i) Compliance Monitoring, (ii) Risk Assessment and Mitigation, and (iii) Enforcement, each performed by its own personnel within MRO. Compliance Monitoring staff conducts audits and spot checks of compliance with Reliability Standards by registered entities. Risk Assessment and Mitigation undertakes an independent review of the facts and circumstances surrounding each violation discovered by Compliance Monitoring, and determines whether sufficient evidence supports each possible violation. Risk Assessment and Mitigation works with the registered entity to develop an effective mitigation plan in the event that a violation is confirmed. Confirmed violations move to the Enforcement

department staff, who review recommendations made by Risk Assessment and Mitigation staff, verify all relevant facts, and evaluate appropriate enforcement actions. The factual review conducted by Risk Assessment and Mitigation and Enforcement staff is intended to ensure a consistent, accurate application of the NERC Reliability Standards. The three-step process also provides for segregation of duties, establishing independence among those making the findings, those assessing risk, and those determining and negotiating penalties and sanctions. MRO believes that this process provides a high level of assurance that determinations are accurate, fair and non-discriminatory.

224. *NERC views **NPCC** as effective in that it is processing and completing identified violations in a timely manner. However, NERC is concerned that NPCC's low level of alleged violations per registered reliability function may indicate that NPCC is not identifying all violations that are occurring. NERC points out that, among the Regional Entities, NPCC had the second highest number of FTEs committed to the compliance program and the highest ratio of registered functions per compliance FTE as of the Performance Assessment filing date. NERC states that it will continue to work with NPCC to improve its process for compliance violation investigations.*

NPCC continues to have a low level of alleged violations per registered reliability function; however, the ratio is in line with several of the other Regional Entities. NPCC credits in part its low level of alleged violations per registered reliability function to its thorough outreach and communication both on an individual basis and through workshops and other forums with the registered entities within its region. Such outreach assists the registered entities in their compliance activities and enhances reliability. In addition, by the end of the assessment period, while NPCC had the lowest number of full-time equivalents (FTEs) committed to the compliance program and the highest ratio of registered functions per compliance FTE, it supplemented its compliance program with independent contractors that perform many of the compliance duties. In this manner, NPCC has been able to build a very cost effective compliance program. NPCC welcomes ERO-wide collaboration on improvements to the process for compliance violation investigations and other process related issues, and is actively involved in RAI-related projects, including running pilots on analyzing registered entities' internal controls, the auditor check list and workbook, and the transition from CIP version 3 to version 5 Reliability Standards.

225. *NERC and its outside auditing firm independently audited **RF's** compliance program and found no material deficiencies. NERC observes that RF was the first Regional Entity to receive approval from the NERC Board of Trustees Compliance Committee for a notice of penalty that imposed a non-zero dollar penalty. NERC notes that RF does need to find ways to increase its efficiency with respect to conducting enforcement activities.*

Since 2009, ReliabilityFirst has taken several steps to increase its efficiency with respect to conducting enforcement activities.

First, ReliabilityFirst has internal violation processing goals that are tied to its overall corporate goals. Second, enforcement staff members hold regular meetings to discuss their plans to meet these violation processing goals. At these meetings, enforcement staff members provide

projected timeframes for the resolution of their matters, and are held accountable to those timeframes. Third, ReliabilityFirst has held formal and informal meetings to better focus enforcement staff on how to tailor their fact gathering efforts and resolving documents to only relevant information. As a result, enforcement staff became more efficient at resolving violations in a shorter amount of time. Fourth, ReliabilityFirst has focused its efforts on those violations that pose the greatest risk to reliability, and expedited its processing of lesser risk violations via the FFT process. To date, ReliabilityFirst has processed approximately 330 FFTs. (Even prior to the FFT process, ReliabilityFirst followed an internal "fast track" process, where it expedited the processing of minimal risk violations in a separate internal process from its other violations.)

ReliabilityFirst's efforts to increase its efficiency in the enforcement process were successful, and to date, ReliabilityFirst has processed over 1,400 alleged violations through NERC and the Commission. The volume of compliance work at ReliabilityFirst has increased significantly since the 2009 self-assessment,[142] but ReliabilityFirst has nevertheless become more efficient at processing violations. As a result, ReliabilityFirst has not only kept up with its caseload, but has simultaneously refined its approach to better focus its efforts on high risk violations and ensuring that major reliability enhancements result from their corresponding enforcement actions. ReliabilityFirst staff's focus on high risk violations is fundamental to regulatory effectiveness as it is critical to prevent staff at the Regional Entities from spending unnecessary amounts of time on minimal risk issues, so they can focus on the high risk issues that are critical to reliability.

226. *NERC views **SERC** as an effective Regional Entity. NERC audited SERC's compliance program and did not find any material deficiencies, but urges SERC to improve on its timeliness in issuing notices of alleged violation. NERC notes that SERC continues to use industry volunteer subject matter experts in addition to its own staff on compliance audits.*

SERC made significant progress during the assessment period to address the concerns raised in 2009. For example, in order to improve violation processing cycle time, SERC staff developed a comprehensive plan that included increasing productivity, improving process and tools, and reviewing staffing levels. This plan was unanimously approved by the SERC Board Executive Committee.[143] Furthermore, SERC implemented process improvements in order to

[142] In 2009, ReliabilityFirst received 169 new violations, and in 2010, this number jumped to 453 violations. In 2011, ReliabilityFirst received 514 violations, in 2012, ReliabilityFirst received 549 violations, and as of August 9, 2013, ReliabilityFirst received 520 violations.

[143] In 2011, SERC removed some collateral duties from Enforcement staff to ensure a focus on violation processing and reduced the ancillary meetings attended by Enforcement staff by 50%. In 2011, SERC developed a corporate metric focused on improving violation processing time, increasing the average number of determinations completed per FTE from 1.4 determinations per month to 4 determinations per month. In 2012, SERC developed a corporate metric focused on improving violation processing to continue its work towards achieving a 12-month violation processing cycle time for Planning and Operations issues. In 2013, SERC developed a corporate metric focused on improving CIP violation processing to continue its work towards achieving a 12-month violation processing cycle time while maintaining a 12-month or less violation processing cycle time for Planning and Operations issues. In addition, SERC provides an ongoing interface and training for Enforcement, legal, and audit staff to allow for discussion of lessons learned and feedback to improve violation assessments and risk statements.

streamline the enforcement process and ensure that SERC has the necessary information to conduct a thorough and timely assessment. These improvements included automation of notification and letters, increased use of requests for information, seminars and outreach, simplified review steps for violation processing, continued use of streamlined enforcement processing (FFT and SNOP), and expanded capabilities for access to CIP evidence and data.

In addition to the increased focus on productivity and process improvements, SERC also has worked to implement organizational efficiencies. To this end, SERC restructured Enforcement staff after a review of other regional structures. Enforcement now reports directly to the vice president and chief program officer, which removes a redundant reporting structure and serves to elevate Enforcement in the organization, given its priority at SERC. SERC has also reviewed its staffing levels and has increased the number of Enforcement staff focused on CIP issues based on the increase in CIP possible violations reported to the region.

As a final matter, with respect to SERC's use of volunteer industry subject matter experts, during the assessment period, the Commission reviewed SERC's use of volunteer industry subject matter experts (ISMEs) on compliance audits as part of its audit of SERC (FERC Docket No. FA12-6-000). FERC found that SERC's use of ISMEs was consistent with the NERC ROP, but did recommend that SERC: (i) revise its process, procedures, and controls regarding ISME participation in compliance activities and ensure SERC has an adequate and detailed set of policies governing ISMEs' participation in compliance activities; and (ii) ensure greater awareness of SERC's ongoing training and education programs and use the feedback from ISME participation in compliance activities to better focus these outreach programs. SERC has committed to implement the recommendations contained in the FERC audit report.

227. *As of the filing date of the Performance Assessment, NERC views* ***SPP Regional Entity*** *as less effective in administering its compliance program than some other Regional Entities. NERC commends SPP Regional Entity for its ability to accurately identify high risk violations, but is concerned about SPP Regional Entity's ability to process alleged violations to completion in a timely manner and its situational awareness capabilities. NERC notes that SPP Regional Entity has been unaware of events that occurred within its footprint, while NERC and the Commission were aware of those events. NERC states that among the Regional Entities, SPP Regional Entity stands eighth in FTEs committed to the compliance program and second in the number of registered functions per compliance FTE.*

SPP RE has significantly reduced the amount of time it takes to process alleged violations to completion. Prior to January 1, 2009, SPP RE's average time to process alleged violations to completion was 24 months, compared to 9.2 months (as of June 30, 2013). The reduction is due to a number of factors, including developing internal Enforcement procedures, streamlining internal Enforcement processing procedures, and increasing the Enforcement staff.[144] SPP RE staff members have also taken several steps to increase their awareness of system events within the region. These steps include SPP RE staff's registering to receive NERC Reliability Coordinator Information System information and *NERC Alerts*, and their receiving and reviewing the *SPP RTO Daily Operations Report*, the *NERC Situational Awareness Morning*

[144] Since January 1, 2009, SPP RE has increased its Enforcement staff from one FTE to ten FTEs and one part-time employee, and has steadily decreased the number of registered functions per compliance FTE to 11.62 (2013 figure).

Report, and the NERC BPS *System Awareness Daily Report*. In addition, SPP RE participates on weekly situational awareness calls with NERC staff, and has increased its outreach through workshops, webinars, newsletters, and personal communication to encourage reporting of events.

228. *NERC rates **TRE** as an effective Regional Entity, commending TRE for focusing on identifying higher risk violations and noting that TRE excels in processing alleged violations through completion. NERC does have questions about a contrast between TRE's high percentage of "failure to perform" violations and low number of violations TRE has recommended for a non-zero dollar penalty. NERC states that it will continue to explore these concerns with TRE.*

In 2007 and 2008, Texas RE recommended zero-dollar penalties in most cases because the Reliability Standards were new and registered entities were still learning how to comply with them. In 2009, in an effort to deter noncompliance, Texas RE began recommending more non-zero dollar penalties for "failure to perform" violations. However, in 2010 Texas RE implemented the Administrative Citation NOP process and by 2012 Texas RE adopted the FFT program. Using the Administrative Citation process and FFT processes, Texas RE stopped recommending monetary penalties for issues involving "failure to perform" if the issues presented low risk to reliability and had been mitigated.

231. *NERC states that **WECC** is "one of the less effective Regional Entities" to date, but notes that WECC made significant progress in the spring of 2009, particularly with respect to processing a backlog of violations. NERC points out that although, as of the Performance Assessment filing date, WECC had the highest level of FTEs committed to the compliance program among the Regional Entities, WECC had the fourth highest ratio of registered functions to compliance FTEs. NERC notes that, due to the violations processing backlog, WECC cancelled all compliance audits scheduled for the fourth quarter of 2008 without coordinating with NERC. According to NERC, WECC also took several other unilateral actions, including issuing compliance bulletins containing Reliability Standards interpretations and/or guidance. NERC indicates that it will continue to work with WECC to resolve these issues. NERC also suggests that WECC create stronger separation between its compliance encouragement efforts and its enforcement activities, examine its staffing levels and compliance processes and stay focused on processing violations to completion. (Footnote omitted.)*

WECC has thoughtfully and thoroughly addressed each of the areas of concern identified in the Three-Year ERO Performance Assessment and the 2010 Order. First, WECC cleared all of its pre-2012 violations caseload by December 31, 2013. As reported to the NERC Board in September 2013, WECC has a caseload index of 8.3 months, ranking third among the Regional Entities.[145] Second, WECC completed all audits contemplated in its annual Implementation Plans. Specifically, during the assessment period, WECC conducted 598 audits and 62 spot checks. The number of audits increased from 90 in 2009 to 165 in 2013, an increase of 83

[145] The caseload index refers to a NERC metric that computes the number of months that it takes to clear the violations that are either in the Regional Entity's inventory, NERC's inventory, or the ERO's inventory based upon the respective average monthly processing rate over the preceding 12-month period. This metric is used to evaluate the efficiency of processing violations over time.

percent. Third, WECC developed and maintains a highly qualified Compliance staff, which increased from 31 to 57 during the assessment period. To further improve its compliance capabilities, in 2013, WECC launched an audit tracking system to assure timely audit completion and document integrity. WECC's internal metric for providing final audit reports to registered entities is 60 days after the close of the audit, a goal which was met 97 percent of the time. Fourth, WECC enhanced, streamlined and documented all of its Enforcement processes, an effort aided by using dedicated subject matter experts and tools such as FFT and expedited settlement agreements. As a result, by the end of the assessment period, WECC was able to process violations from intake through filing with NERC in less than five months, on average. Fifth, WECC successfully implemented new IT solutions and systems, and provided extensive training to registered entities on the new systems. Sixth, WECC expanded and enhanced its compliance encouragement and outreach efforts while ensuring "adequate separation between compliance encouragement efforts and its enforcement activities." This was accomplished in part by personnel changes and strengthening the role of the director of stakeholder outreach. Finally, WECC worked collaboratively with the other Regional Entities and NERC to bring forward the Omnibus proposal; proposed Rules of Procedure changes to streamline TFE processing; developed new registration system tools; and actively participated in several ongoing NERC IT projects, lending expertise and practical experience.

SPP Independence

In the 2010 Order, the Commission laid out its initial concerns about the possible conflicts of interest between SPP RE and SPP RTO, and emphasized the heavy burden on SPP RE to demonstrate a strong separation of functions between the two organizations.[146] As a consequence, the Commission had required NERC to provide an appropriate discussion of SPP RE's bylaws in its first performance assessment. In response to NERC's submission, the Commission generally found that SPP RE had achieved sufficient separation from SPP RTO, citing in particular SPP RE's efforts to ensure that its standards development process was not unduly influenced by the RTO.[147] While the Commission's analysis in the 2010 Order does not necessarily require a further response at this time, SPP RE would like to point out that the Commission's second audit of SPP RE, which was finalized in 2011, reinforced the adequacy of Regional Entity's separation from the RTO.[148] Among other things, the second audit report described how SPP RE's general manager is the primary contact between NERC and SPP RE, with responsibility for administering SPP RE's programs under the Delegation Agreement. The report also described how SPP RE is governed by three independent trustees who operate separately from the SPP RTO board of directors, and that SPP RE trustees have autonomy over decisions in fund allocation and approval of SPP RE's budget, as well as oversight of SPP RE decisions on regional Reliability Standards, compliance enforcement actions, and penalties. In addition, as the report set out, SPP RE's organizational structure makes it independent from the

[146] *See* 132 FERC ¶ 61,217 (2010), at P 232.

[147] *See id*. PP 237-241.

[148] *See generally Audit of Regional Entity Operations at Southwest Power Pool (SPP) for Compliance with its Bylaws, Delegation Agreement, Membership Agreement, and its Independence as an Regional Entity*, Final Audit Report, Delegated Order (October 5, 2011).

RTO in its performance of CMEP functions while linking with shared resources to use their expertise when performing delegated functions outside of the CMEP. Finally, the report detailed how SPP RE has reduced its reliance on shared staff and increased the number of FTEs since January 1, 2009.[149]

WECC Voting Structure

In the 2010 Order, the Commission took note of some initial concerns that NERC had regarding the effectiveness of WECC's stakeholder voting structure, but that those concerns had been largely allayed by changes to WECC's bylaws and its process for developing and approving regional Reliability Standards.[150] WECC continues to improve its regional Reliability Standards development process. For example, on March 1, 2012, the Commission approved WECC's revised RRSDP, which call for voting by eligible members of the WECC Ballot Body rather than by a lead Standing Committee of WECC. In addition, WECC has developed a web-based system for balloting, and make all the proceedings of the standards drafting teams available using WECC's website. Available information includes notification of meetings, team meeting agenda and minutes, draft and final documents and supporting documents. Finally, WECC strives for continuous improvement and is always open to feedback from the various committees, standards drafting teams, and stakeholders at large.

[149] *See id*., at pp. 5-7.

[150] *See* 132 FERC ¶ 61,217 (2010), at P 243.

Appendix C
Regional Entities' Satisfaction of Statutory and Regulatory Criteria

During the 2009 through 2014 assessment period, all eight Regional Entities continued to satisfy the three sets of criteria set out in FPA §215(e)(4), 16 U.S.C. §824o(e)(4), as reiterated in §39.8 of the Commission's regulations, 18 C.F.R. §39.8 (2013), to maintain the authority delegated to them by the ERO, as approved by the Commission, to propose and enforce mandatory Reliability Standards. The three sets of criteria are:

1. The Regional Entity is governed by an independent board, a balanced stakeholder board or a combination independent and balanced stakeholder board.

2. The Regional Entity meets the requirements otherwise applicable to the ERO in FPA §215(c)(1) and (2), 16 U.S.C. §824o(c)(1)(2), namely that it (a) has the ability to develop and enforce reliability standards that provide for an adequate level of reliability of the bulk-power system; and (b) has established rules that (i) assure its independence of the users and owners and operators of the bulk-power system, while assuring fair stakeholder representation in the selection of its directors and balanced decision-making in any ERO committee or subordinate organization structure, (ii) allocate equitably reasonable dues, fees, and other charges among end users for all activities, (iii) provide fair and impartial procedures for enforcement of reliability standards through the imposition of penalties, (iv) provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing reliability standards and otherwise exercising its duties, and (v) provide for taking appropriate steps to gain recognition in Canada and Mexico,

3. The Regional Entity operates under a delegation agreement that promotes effective and efficient administration of bulk-power system reliability.

Specifically, the eight Regional Entities continued to satisfy the statutory and regulatory criteria for their delegated authority as follows:

Florida Reliability Coordinating Council, Inc. (FRCC)

1. **FRCC "is governed by an independent board, a balanced stakeholder board or a combination independent and balanced stakeholder board."** The FRCC board of directors (FRCC Board) is a balanced stakeholder board. The FRCC Board has a minimum of sixteen (16) members, who are allocated among the region's six sectors, and the chief executive officer (CEO). The sector representation is as follows: (i) three directors from the Suppliers Sector; (ii) two directors from the Non-Investor Owned Utility Wholesale Sector; (iii) two directors from the Load Serving Entity Sector (one Municipal and one Cooperative); (iv) three directors from the Generating Load Serving Entity Sector; (v) three directors from the Investor Owned Utility Sector; and (vi) two directors from the General Sector. FRCC's CEO is an ex-officio non-voting director. Directors are elected by their sector and serve two-year terms.

2. **FRCC meets the requirements of Federal Power Act Section 215 (c)(1)(2), because**:
   a. **FRCC is able to develop and enforce reliability standards that provide for an adequate level of reliability of the bulk power system**. The FRCC has a RRSDP that is based on the set of common attributes that provide for an open, balanced, fair, transparent and inclusive process. During the assessment period, FRCC placed two standards development projects on hold awaiting the completion of NERC standards development projects, and terminated one project as NERC's continent-wide standard was determined to be sufficient for FRCC reliability needs. Finally, the FRCC Registered Ballot Body and FRCC Board approved one project, which was nevertheless held in abeyance while the adequacy of the NERC continent-wide standard was evaluated, and will be withdrawn if the NERC Reliability Standard is determined to be sufficient for FRCC's needs. FRCC prefers the development of continent-wide standards, but will follow its RRSDP should a need arise for a more stringent standard or a standard to cover an area that NERC standards do not.

      Compliance monitoring and enforcement of Reliability Standards is carried out by FRCC compliance staff which grew during the assessment period. FRCC enforcement staff began reporting directly to the vice president and executive director of standards and compliance in 2012, while the monitoring staff continued to report to the director of compliance. FRCC implemented this separation to provide more independence in enforcement decisions.

      FRCC took additional steps to enforce reliability standards and provide an adequate level of reliability for the BPS. For example, its Compliance staff developed approximately 30 detailed internal procedures for all aspects of the compliance process, which were regularly reviewed and updated. These procedures helped promote consistent and effective application of its internal procedures and ensured that it met the obligations in the NERC ROP. In addition, FRCC upgraded its compliance portal application in 2012, to provide needed enhancements to protect security of the application and data held within the application along with providing some desired improvements in the use of many of its components.

      FRCC improved its enforcement caseload processing during the assessment period, and also experienced a reduction of new violations in the last two years of that period. FRCC attributes the reduction in new violations in part to increased understanding of the registered entities in what the requirements mean and what their compliance expectations are. In addition to this reduction, FRCC worked hard to streamline its enforcement activities to utilize the available processes and were able to reduce its caseload index to approximately 6.5.

   b. **FRCC has established rules that:**
      i. **Assure its independence of the users and owners and operators of the bulk-power system, while assuring fair stakeholder representation in the selection of its directors and balanced decision-making in any ERO committee or subordinate organization structure.** During the assessment period, FRCC implemented an annual employee recital and disclosures, which

includes a copy of the *FRCC Conflict of Interest Policy* and a process where each employee signs a *Conflict of Interest Questionnaire*, a *Disclosure Statement of Stock Ownership of FRCC Member Companies* and a *Non-Disclosure Acknowledgement*. As previously described, the governance of the FRCC is performed by a balanced stakeholder board, which assures fair stakeholder representation while also practicing balanced decision making where no one sector can block or no two sectors can pass any decision.

ii. **Allocate equitably reasonable dues, fees, and other charges among end users for all activities.** The funding for the FRCC Regional Entity division is allocated among the FRCC load serving entities (LSEs) through a formula which is based on NEL. Each entity reports, on an annual basis, the NEL for the previous year. After the FRCC reviews this information, it is provided to NERC as part of the business plan and budget development process. The FRCC develops an annual budget each year, which is based on common assumptions that have been developed collaboratively by NERC and the eight Regional Entities, and which provides for the resources to carry out all of its delegated functions. The budget and accompanying LSE assessments are approved by the FRCC Board, the NERC Board, and the Commission.

iii. **Provide fair and impartial procedures for enforcement of reliability standards through the imposition of penalties**. The FRCC has adopted the NERC CMEP, Appendix 4C to the NERC ROP. This is the primary document that the FRCC uses to provide fair and impartial procedures for enforcement. With respect to the calculation of penalties, the FRCC consistently uses the penalty calculator tool provided by NERC in order to provide a consistent application of the penalty and sanctions guidelines. In addition, the FRCC Board and their alternates are required to sign a *Code of Conduct* that obligates each of them to act in the best interest of FRCC and refrain from involvement in any situation where there is an actual or potential conflict of interest. In addition, since the FRCC Board is a balanced stakeholder board, FRCC does not allow members of the board to participate directly in settlement discussions with FRCC on behalf of their registered entities to avoid any conflict of interest or undue influence situation.

iv. **Provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing reliability standards and otherwise exercising its duties**. FRCC has a RRSDP that is based on the required set of common attributes that provide for an open, balanced, fair, transparent and inclusive process. The process has the following characteristics:

- Due Process – Any entity that is directly and materially affected by the reliability of the FRCC BPS has a right to participate in this process.

- Openness – Participation is open to any entity that is directly and materially affected by the reliability of the FRCC BPS. Participation is not conditional upon membership in the FRCC. All FRCC RRSDP meetings will be open and noticed on the FRCC website.

- Balance – The FRCC RRSDP process shall have a balance of interests and shall not be dominated by any two interest categories and no single interest category shall be able to defeat a matter.

The FRCC also provides reasonable notice and opportunity for public comment in its compliance monitoring and enforcement activities as required by the CMEP and the NERC ROP.

v. **Provide for taking appropriate steps to gain recognition in Canada and Mexico**. This criterion is not applicable to the FRCC region.

3. **FRCC operates under a delegation agreement that promotes effective and efficient administration of bulk-power system reliability**. On June 12, 2012, the Commission approved the amended and restated FRCC Delegation Agreement which incorporated benefits of NERC's and FRCC's mutual experience and lessons learned while operating under the predecessor agreement. The revised Delegation Agreement provides for more efficient and effective execution of responsibilities that promote the reliability of the BES. These responsibilities include: (i) development and proposal of Reliability Standards; (ii) enforcement of compliance with Reliability Standards; (iii) certification of BPS entities; (iv) registration of owners, operators, and users of the BPS; (v) reliability assessment and performance analysis; (vi) event analysis and reliability improvement; (vii) training and education; and (viii) situation awareness and infrastructure security.

Midwest Reliability Organization (MRO)

(1) **MRO "is governed by an independent board, a balanced stakeholder board or a combination independent and balanced stakeholder board.**" During most of the assessment period, MRO was governed by a balanced stakeholder board. On June 25, 2012, the Commission approved MRO's proposal to change from a balanced stakeholder board to a combination independent and balanced stakeholder board. MRO's two independent board members were elected for terms beginning January 2013; they bring cyber and data security expertise to the MRO Board's set of executive and technical skills and expertise.

(2) **MRO meets the requirements of Section 215 (c)(1)(2) of the Federal Power Act, because**:

a. MRO is able to develop and enforce reliability standards that provide for an adequate level of reliability of the bulk power system. MRO supports the development of continent-wide standards to maintain the reliable operations of the BES as opposed to regional Reliability Standards, particularly in the Eastern Interconnection, and decided during the assessment period to forego the development of regional

standards. Nevertheless, MRO has a RRSDP manual, which is found in Exhibit C to its Delegation Agreement with NERC, and a stakeholder Standards Committee comprised of subject matter experts in the event there was a need for a regional Reliability Standard in the future.

MRO also has the requisite staff both in terms of number of people and expertise, and adequate processes and procedures, to enforce the operating and CIP Reliability Standards. Notably, during the assessment period, MRO split the CMEP function into three distinct steps with their own assigned personnel— (i) Compliance Monitoring, (ii) Risk Assessment and Mitigation, and (iii) Enforcement. Compliance monitoring staff conducts audits and spot checks of compliance with reliability standards by registered entities. Risk Assessment and Mitigation undertakes an independent review of the facts and circumstances that surround each violation discovered by Compliance Monitoring, and determines whether sufficient evidence supports each possible violation. Risk Assessment and Mitigation also works with the registered entity to develop an effective and comprehensive mitigation plan in the event that a violation is confirmed. Confirmed violations move to the Enforcement department staff, who review recommendations made by Risk Assessment and Mitigation staff, verify all relevant facts, and evaluate appropriate enforcement actions.

The factual review conducted by Risk Assessment and Mitigation and Enforcement staff is intended to ensure a consistent, accurate application of the NERC reliability standards. The three-step process also provides for segregation of duties, establishing independence among those making the findings, those assessing risk, and those determining and negotiating penalties and sanctions. As a result of this approach, registered entities in the MRO region accept responsibility in 90% of all violations and settlements are reserved only for the more complicated compliance matters (thus, expediting less serious violations and lowering administrative costs).

b. MRO has established rules that:

i. **Assure its independence of the users and owners and operators of the bulk-power system, while assuring fair stakeholder representation in the selection of its directors and balanced decision-making in any ERO committee or subordinate organization structure.** In particular, MRO assures the independence of the users and owners and operators of the BPS by establishing processes and procedures for the conduct of its work. For example, by having a three-step process to implement the CMEP, MRO assures that its internal work is subjected to review and validation. MRO also has specific policies that prevent stakeholder conflicts of interest and prevent stakeholders from participating in its CMEP work. In addition, all MRO members elect the two independent directors; the remaining directors are elected by his or her sector.

ii. Allocate equitably reasonable dues, fees, and other charges among end users for all activities. MRO's funding requirements are equitably allocated in a manner similar to the one used by the other Regional Entities. Each year,

MRO develops an annual business plan and budget that describes in detail the resources MRO needs to carry out its delegated functions. The annual business plan and budget is reviewed and approved by the MRO Board and then submitted to NERC and ultimately filed with the Commission for approval. Assessments are made to MRO's LSEs through a formula which is based on NEL. MRO does not charge additional fees to be a member or to participate in its training. The annual business plan and budget as well as annual audits by independent auditors and periodic audits by FERC help ensure that MRO's expenses and assessments to end users are reasonable.

iii. **Provide fair and impartial procedures for enforcement of reliability standards through the imposition of penalties**. To ensure fair and impartial procedures, as described above, MRO has implemented a three-step approach to fulfill its delegated responsibilities under the CMEP. MRO Compliance Monitoring staff conducts compliance monitoring activities, including audits, self-certifications, and spot checks. Risk and Mitigation staff is responsible for scoping MRO's compliance monitoring work under RAI. Risk and Mitigation staff also works with the entity to develop a thorough, comprehensive, and effective mitigation plan, not only to resolve the concern but to prevent recurrence of the noncompliance. MRO Enforcement staff completes the process by reviewing any recommendations from MRO Risk Assessment and Mitigation staff, verifying that all relevant facts have been gathered, and evaluating the possible violation for the appropriate enforcement action.

There are many factors which may affect a penalty determination. MRO does not utilize the penalty calculator/SIV tool for most minimal risk concerns, as those violations are currently resolved through the FFT process and under RAI, they will be primarily resolved as compliance exceptions outside the enforcement process. The penalty calculator/SIV tool is used as a resource for violations that pose greater risk. As a result of the extensive risk assessment conducted by MRO Risk Assessment and Mitigation staff, Enforcement is able to make fair, accurate and reasonable enforcement decisions scaled on the risk posed by an individual violation – the greater the risk, the greater the penalty and scrutiny of review and approval.

In addition MRO has policies and procedures to avoid conflicts of interest in its CMEP work. Those policies and procedures provide:

(1) No MRO director or member of MRO committees may participate in any way in compliance violation investigations, compliance audits, reports, sanction determinations, or other matters within the CMEP.

(2) An MRO director or member of an MRO committee may engage in actions on behalf of his or her employer regarding a compliance monitoring and enforcement matter undertaken by MRO; however,

that director or member of an MRO committee must recuse himself or herself from any board or committee decisions, meetings, and actions related to that compliance monitoring and enforcement matter. Potential concerns about the participation of a MRO director or member of an MRO committee are brought to the attention of the president and CEO who will seek an appropriate resolution of the matter with the advice and counsel of the independent directors.

iv. **Provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing reliability standards and otherwise exercising its duties**. MRO does not have any regional Reliability Standards and does not anticipate developing any regional Reliability Standards because of its strong support for continent wide, or at least interconnection wide, standards. Nevertheless, MRO has a RRSDP manual which has been approved by NERC and FERC. This RRSDP manual is based on the set of common attributes that provide for an open, balanced, fair, transparent and inclusive process, and includes specific provisions relating to the process for the opportunity to comment and be heard.

v. **Provide for taking appropriate steps to gain recognition in Canada**. MRO operates under provincial Manitoba regulations which were adopted in 2012. Prior to the adoption of regulations, MRO had a memorandum of understanding with Manitoba Hydro.

During the assessment period, MRO also had a memorandum of understanding with Saskatchewan Power Corporation and NERC governing MRO's work in Saskatchewan, Canada.

(3) **MRO operates under a delegation agreement that promotes effective and efficient administration of bulk-power system reliability**. MRO has adopted principles associated with the theory of a "Highly Reliable" organization in its approach to its delegated responsibilities, an approach that has positioned MRO and its registered entities to move to the risk based approach contemplated by RAI. These principles recognize risk, and emphasize self-monitoring with strong corrective action programs. The approach has fostered greater engagement with registered entities to solve technical problems and resulted in a corporate theme—clarity, assurance, and results (CAR). Clarity sets clear expectations for registered entities on the technical requirements of the standards. Assurance measures performance against these key requisites. Results can be seen in improved reliability. For example, MRO leveraged the technical expertise of subject matter experts on stakeholder-led committees to develop application guides for NERC standards that provide clear expectations of compliance. While these application guides are not authoritative, they provide much needed direction on compliance requirements. As a result, MRO has seen a measurable drop in the frequency and severity levels of violations in higher risk standards, beginning with the most violated Reliability Standard several years ago, PRC-005.

Additionally, during the assessment period, an MRO stakeholder-led committee developed an internal controls and procedures framework for use by registered entities to strengthen their internal compliance programs. These types of guidelines provide the necessary clarity to industry to assure that key reliability requirements are met. This has now become part of a pilot project under RAI.

Registered entities, too, need to provide assurance to MRO staff that they understand the requirements and have established sustainable management practices to detect, correct, report, and prevent problems. For example, MRO staff sampled self-reported violations from 2013. In 90% of these violations, the registered entity's assessment of risk matched MRO's staff assessment of risk. When registered entities and MRO staff view risk the same way and accept responsibility, they have greater day-to-day, sustainable assurance.

Northeast Power Coordinating Council, Inc. (NPCC)

1. **NPCC "is governed by an independent board, a balanced stakeholder board or a combination independent and balanced stakeholder board."** On October 17, 2011, the Commission approved NPCC's proposal to change its board to a hybrid (combination independent and balanced stakeholder) board. That change became effective on January 1, 2012. NPCC's board of directors consists of seven stakeholder voting sectors that each consist of a maximum of two directors per sector, an independent sector consisting of two independent directors, an independent board chair with voting rights to preclude board deadlocks, and the president and CEO. Within NPCC, no two sectors can control and no one sector can block action.

2. **NPCC meets the requirements of Section 215(c)(1)(2) of the Federal Power Act, because:**
    a. **NPCC is able to develop and enforce reliability standards that provide for an adequate level of reliability of the bulk power system.** NPCC has developed a RRSDP that provides the design-basis approach to a consensus building process by which NPCC may develop regional Reliability Standards and regional variances to be proposed to the ERO for adoption, under delegated authority by the FERC and the Canadian provincial regulatory and/or governmental authorities. This procedure contains common attributes that provide for an adequate level of reliability to provide for an open, balanced, fair, transparent, and inclusive standards development process. NPCC's RRSDP sets forth the structure for developing reliability standards that provide for an adequate level of reliability.

    Illustratively, during the assessment period, NPCC developed a disturbance monitoring regional Reliability Standard, PRC-002-NPCC-01, to ensure that adequate disturbance data is available to facilitate BES event analyses. The Reliability Standard addresses a specific recommendation from the *August 14, 2003 Blackout Final NERC Report - Conclusions and Recommendations* (July 13, 2004) regarding the use of time-synchronized data recorders.[151] Substantively, the Reliability Standard outlines the basic requirements for the type, location and capability of

[151] *See* http://www.nerc.com/pa/rrm/ea/Pages/Blackout-August-2003.aspx.

equipment to be placed on the power system to enable the analysis of grid disturbances effectively and efficiently. The Reliability Standard is intended to fill the reliability gap related to disturbance monitoring and reporting by establishing enforceable disturbance monitoring and reporting requirements for the NPCC region.

Compliance and enforcement activities are carried out by the NPCC compliance staff and are independent of all users, owners and operators of the international BPS and from the hearing officer. Compliance and enforcement activities are governed in the U.S. by the Delegation Agreement between NERC and NPCC, delegating portions of NERC's authority as the ERO to NPCC. In addition, pursuant to an agreement between NPCC and WECC that was approved by the Commission, NPCC assumed responsibility for the CMEP with respect to the WECC RC function and the WECC IA function from January 1, 2012 through the end of the assessment period.

Examples of NPCC's efforts to monitor compliance with, and enforcement of, the reliability standards include its use of extensive pre-audit data collection and pre-audit conference calls with the registered entities. NPCC staff thoroughly reviews the first round of data submittals, and via questions, routinely collects a second round of data from the registered entity before the audit is performed. From these pre-audit activities, NPCC is able to conduct a more targeted audit. This results in an efficient and effective audit for both NPCC and the registered entity. This efficiency also permits the auditors to drill down into other areas and to make recommendations to the registered entity for enhanced reliability performance. In addition, during the assessment period, developed an enforcement dashboard, highlighting the regional caseload index and the status of mitigation plans associated with high risk violations among other compliance parameters. The enforcement dashboard is an informational tool to both management and to the industry.

NPCC amended its hearing procedures to provide for a hearing body comprised of an independent hearing officer and two independent directors. As a result of the amendments, the hearing body will always be comprised of independent members and will not have stakeholder members to assure enforcement of reliability standards provides for an adequate level of reliability.

b. NPCC has established rules that:

i. **Assure its independence of the users and owners and operators of the bulk-power system, while assuring fair stakeholder representation in the selection of its directors and balanced decision-making in any ERO committee or subordinate organization structure**. The rules and procedures contained in the Delegation Agreement, ROP, amended and restated NPCC bylaws, and other NPCC committee governance documents assure the independence of the users and owners and operators of the BPS while assuring fair stakeholder representation and balanced decision-making at the same time. Fair stakeholder representation and participation is assured by NPCC's committees, subcommittees, task forces and other groups as the board of directors may deem appropriate. Industry technical experts from

within the membership also provide valuable input to the board through various working groups and task forces as well as the committees.

ii. **Allocate equitably reasonable dues, fees, and other charges among end users for all activities.** The allocation of dues, fees, and other charges by NPCC is governed by Article XIII of its bylaws. Funding of Regional Entity division activities are undertaken pursuant to FPA §215 in accordance with the funding provisions and procedures of that law and related FERC regulations and orders. The NPCC board of directors approves the annual Business plan and Budget in time for submission to the ERO and to FERC for approval. NPCC funds reliability activities in Canadian provinces pursuant to the mechanisms established by the applicable Canadian provincial regulatory authority. Budgets for the costs of reliability activities are allocated equitably based on the NEL and other relevant factors consistent with applicable law, the Delegation Agreement, and any agreements with Canadian provincial authorities. NPCC members are not assessed an annual membership fee. For NPCC's Criteria Services division, which establish and monitor regional-specific non-statutory criteria, full members that perform the balancing authority function are assessed and pay based upon a NEL. Special assessments for Criteria Services may be separately budgeted to full members that perform the balancing authority function or upon Full Members with full members' consent.

iii. **Provide fair and impartial procedures for enforcement of reliability standards through the imposition of penalties**. The NERC ROP is the primary document that NPCC uses to provide fair and impartial procedures for enforcement. Additionally, NPCC has in place *Conflict of Interest Guidelines* that require each NPCC director, officer, and employee to avoid and refrain from involvement in situation where there is an actual conflict of interest, disclose any actual or potential conflicts of interest that may arise, recuse himself or herself from participation in any action involving an actual or potential conflict of interest, and refrain from voting on any actions where there is an actual or potential conflict of interest. In addition, NPCC's *Code of Conduct*, which applies to its officers, board of directors, employees, and all participants of NPCC committees, task forces, and working groups, requires each individual to recognize conflicts of interest that may arise and to take steps to disclose such conflicts of interest and to refrain from voting and/or influencing others with respect to such conflicts of interest. With respect to penalties, NPCC consistently uses the penalty calculator tool for consistency in penalty calculation determinations

iv. **Provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing reliability standards and otherwise exercising its duties**. NPCC follows a RRSDP that provides that participation in the development of a regional Reliability Standard shall be open to all organizations that are directly and materially

affected by the NPCC BPS reliability, that there shall be no undue financial barriers to participation, that participation shall not be conditioned upon membership in NPCC or unreasonably restricted on the basis of technical qualifications or other such requirements. Meetings of drafting teams are open to the NPCC members and others.

Compliance and enforcement activities are carried out by the NPCC compliance staff and are independent of all users, owners and operators of the international BPS and from the hearing officer. Compliance and enforcement activities are governed in the U.S. by the Delegation Agreement between NERC and NPCC, delegating portions of NERC's authority as the ERO to NPCC. NPCC's hearing procedures provide for a hearing body comprised of an independent hearing officer and two independent directors.

v. **Provide for taking appropriate steps to gain recognition in Canada and Mexico**. NPCC has MOUs in place with the Northeastern Canadian provinces (New Brunswick, Nova Scotia, Ontario, and Quebec). At the end of the assessment period, NPCC was in the process of updating and revising MOUs to respond to recent Canadian legislative and regulatory changes and initiatives.

3. **NPCC operates under a delegation agreement that promotes effective and efficient administration of bulk-power system reliability**. Effective January 1, 2012, NPCC executed an amended and restated Delegation Agreement, which delegated to NPCC certain activities pursuant to FPA §215. These delegated activities include certification of BPS Entities, registration of owners, operators, and users of the BPS as responsible for compliance with requirements of Reliability Standards, developing assessments of the reliability of the BPS, developing and maintaining, and collecting data in support of the development and maintenance of, reliability performance metrics and assessments of risks to the reliable operation of the BPS, conducting and coordinating event analysis, providing training and education to registered entities, and gathering and assessing situation awareness information. NERC has also delegated NPCC the authority to propose Reliability Standards, regional variances, or modifications thereof to NERC and to develop regional Reliability Standards. In summary, the Delegation Agreement promotes the effective and efficient administration of the BPS by clearly identifying the delegation of authority provided to NPCC.

ReliabilityFirst Corporation (RF)

1. **RF "is governed by an independent board, a balanced stakeholder board or a combination independent and balanced stakeholder board**." RF is governed by a combination independent and balanced stakeholder board, which consists of 14 directors: (i) three are independent directors; (ii) three are at-large directors elected by all the industry sectors voting together as a single class; and (iii) eight are elected by their industry sectors (suppliers elect two directors, transmission companies elect two directors, RTOs elect one

director, small LSEs elect one director, medium LSEs elect one director, and large LSEs elect one director).

2. **RF met the requirements of Section 215 (c)(1) (2) of the Federal Power Act, because**:
   a. **RF is able to develop and enforce reliability standards that provide for an adequate level of reliability of the bulk power system**. Although RF no longer develops regional Reliability Standards in order to avoid duplication with the NERC continent-wide Reliability Standards, RF has adopted a RRSDP, and has otherwise proved its ability to develop regional Reliability Standards, as illustrated by its development of RF's BAL-502-RFC-02 (Planning Resource Adequacy Analysis, Assessment and Documentation), which was approved by the Commission on March 17, 2011.

      RF has sufficient staff with the requisite expertise to conduct compliance audits, investigations, spot checks, and other compliance reviews, and to enforce Reliability Standards as demonstrated in part by its performing over 290 audits and over 200 spot checks during the assessment period, and ensuring the mitigation of over 1,400 alleged violations of those standards. These enforcement activities have resulted in tangible improvements to the reliability of the BPS. To enhance its risk-determination process in enforcement, RF developed a "Risk-Harm" process which, among other things, provided for technical experts to answer a series of questions about the risk and harm posed by each violation using a common scale to ascertain a quantified risk assessment for each violation. Additionally, for serious violations of the NERC Reliability Standards, RF works with registered entities to implement substantial "above and beyond" activities to enhance reliability on their system and on the BPS.

   b. **RF has established rules that**:
      i. **Assure its independence of the users and owners and operators of the bulk-power system, while assuring fair stakeholder representation in the selection of its directors and balanced decision-making in any ERO committee or subordinate organization structure.** As described earlier, RF is governed by a combination independent and balanced stakeholder board. Pursuant to RF's bylaws, no two industry sectors can control any RF decision and no single industry sector can veto any RF decision. This hybrid board structure assures RF's independence, while still assuring fair stakeholder representation and balanced decision-making. To further assure RF's independence of the users, owners and operators of the BPS, RF has the following protections in place:

         - First, RF adopted the NERC CMEP, Appendix 4C to the NERC ROP, which provides fair and impartial procedures for the monitoring and enforcement of Reliability Standards.

         - Second, all RF employees and contractors sign and must adhere to non-disclosure and confidentiality agreements and conflict of

interest forms, and RF employees, contractors, and directors are governed by the RF *Conflict of Interest Policy*, the RF *Code of Business Conduct and Ethics*, and §1500 of the NERC ROP.

- Third, to ensure the independence of its staff and eliminate any potential conflicts of interest, RF does not allow stakeholder participation in its compliance or enforcement activities (i.e., a registered entity staff member may not be on an RF audit or compliance investigation team).

- Fourth, RF does not allow its industry sector directors to participate in settlement discussions with RF on behalf of their registered entity.

ii. **Allocate equitably reasonable dues, fees, and other charges among end users for all activities**. The funding for RF's activities is equitably allocated among its end users and recovered through a formula based on NEL. Each year, RF develops an annual business plan and budget, which describes the adequate resources needed for RF to carry out its delegated functions. The annual business plan and budget and the assessments to the end users must be approved by the Commission. The annual business plan and budget process, the Commission's approval of the assessments, and periodic financial audits by the Commission all ensure that RF's expenses and assessments to end users are reasonable.

iii. **Provide fair and impartial procedures for enforcement of reliability standards through the imposition of penalties.** RF has adopted the NERC CMEP, Appendix 4C to the NERC ROP, which provides fair and impartial procedures for the enforcement of Reliability Standards within RFC's geographic boundaries. Additionally, RF maintains the RF *Conflict of Interest Policy* and the RF *Code of Business Conduct and Ethics* to ensure the integrity and independence of its compliance and enforcement staff. To assess fair, impartial, and consistent penalties, RF follows the *Sanction Guidelines*, as set out in ROP Appendix 4B.

iv. **Provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing reliability standards and otherwise exercising its duties.** Although RF no longer develops regional Reliability Standards, RF's RRSDP provides for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in the development of Reliability Standards.

The RRSDP includes public notice and a comment period for any proposed standard, due consideration of those public comments, and a ballot of interested stakeholders. Participation in the standards development process is open to all entities that are directly and materially affected by reliability in the

RF region, and there are no undue financial barriers to participation. The standards development process is balanced: it may not be dominated by any two interest categories, and no single interest category shall be able to defeat a matter.

RF provides for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in its CMEP activities. A registered entity has the right to receive notice when it is placed on the NCR, and may appeal their registration to NERC and to the Commission.

The CMEP requires RF to provide notice to a registered entity when it determines that the registered entity has violated a Reliability Standard, and the registered entity has an opportunity to respond. If a registered entity wishes to contest an alleged violation of a Reliability Standard or a penalty, it may request and receive a hearing, and may appeal the hearing decision to NERC. A registered entity also has the right to request a hearing to contest a twice-rejected mitigation plan or a remedial action directive.

At the conclusion of an enforcement matter, NERC publicly files a NOP with the Commission, which promotes openness and the opportunity for public comment. The ERO balances the interest in openness with the concern for the security of critical infrastructure information, and as such, all sensitive critical infrastructure information is redacted from all public NOP filings.

v. **Provide for taking appropriate steps to gain recognition in Canada and Mexico.** This criterion is not applicable to RF, as its geographic boundaries do not include any portion of Canada or Mexico.

3. **RF operates under a delegation agreement that promotes effective and efficient administration of bulk-power system reliability**. Effective January 1, 2011, RF executed an amended and restated regional Delegation Agreement with NERC, which delegated to RF certain activities pursuant to FPA §215. These delegated activities include: (i) certification of BPS entities; (ii) registration of owners, operators, and users of the BPS responsible for compliance with the requirements of Reliability Standards; (iii) reliability assessment and performance analysis; (iv) event analysis and reliability improvement; (v) training and education; (vi) situational awareness and infrastructure security; (vii) the development and proposal of Reliability Standards to NERC; (viii) monitoring of compliance with Reliability Standards; and (ix) enforcement of compliance with Reliability Standards. These delegated activities are necessary for the effective administration of BPS reliability. RF only performs those activities delegated to it under the Delegation Agreement. This ensures that RF is not distracted by any other activities, and in turn promotes the efficiency and effectiveness of the corporation's efforts to improve reliability.

SERC Reliability Corporation (SERC)

1. **SERC "is governed by an independent board, a balanced stakeholder board or a combination independent and balanced stakeholder board**." SERC is governed by a balanced stakeholder board. Stakeholders are classified by the SERC Board Executive Committee in one of seven sectors (investor-owned utility sector, federal/state sector, cooperative sector, municipal sector, marketer sector, merchant electricity generator sector, and ISO-RTO sector). SERC's bylaws establish voting rules that ensure that no two sectors are able to approve a decision and that no one sector can veto a decision.

2. **SERC met the requirements of Section 215 (c)(1)(2) of the Federal Power Act, because**:
   a. **SERC is able to develop and enforce reliability standards that provide for an adequate level of reliability of the bulk power system**.

      Standards: The SERC RRSDP defines the process for the development, revision, reaffirmation, and withdrawal of regional Reliability Standards. The SERC RRSDP requires any proposed regional Reliability Standard to be more stringent than a continent-wide Reliability Standard, whether the regional Reliability Standard addresses matters that the continent-wide Reliability Standard does not or the regional Reliability Standard is necessitated by a physical difference in the BPS within the SERC region. SERC regional Reliability Standards are required to provide for as much uniformity as possible with continent-wide reliability standards. Proposed SERC regional reliability standards are subject to approval by NERC and FERC prior to becoming mandatory and enforceable within the SERC region.

      SERC has one FERC-approved regional Reliability Standard, PRC-006-SERC-01, which addresses automatic underfrequency load shedding requirements. SERC currently is not developing any additional Regional Reliability Standards because the continent-wide NERC Reliability Standards are presently adequate for the SERC region. SERC also participates in the NERC Standards Committee, hosts biannual meetings of the SERC Standards Committee, and hosts specific commenting sessions for NERC Standards Projects as NERC requests comments, all of which involve the discussion of proposed changes to NERC Reliability Standards.

      Compliance: SERC's authority to monitor reliability standards is based on the authority granted in its Delegation Agreement with NERC. SERC has the expertise on staff to conduct compliance audits, investigations, spot checks and other compliance reviews for the Operating, Planning, and CIP Reliability Standards. SERC develops and posts an annual CMEP implementation plan that is complementary to the NERC CMEP, but also addresses reliability issues specific to the SERC region. SERC builds upon the NERC actively monitored list and incorporates additional Standards or Requirements that relate to the SERC region's BES. SERC utilizes off-site and on-site audits, spot checks, and other compliance monitoring methods to assess registered entity compliance with NERC Reliability Standards. Compliance prepares detailed reports on each audit and makes

recommendations to Enforcement about possible violations of NERC Reliability Standards.

Enforcement: Over the past five years, SERC has demonstrated its ability to enforce Reliability Standards by processing approximately 800 alleged violations originating from audits, spot checks, self-certifications, complaints, self-reports, and compliance investigations following the requirements of the CMEP and NERC ROP. Enforcement staff conducts a thorough assessment of all possible violations to determine whether there is a sufficient basis to allege a violation. If a sufficient basis exists, Enforcement staff determines the complete scope of the violation and the actual and potential risk to the reliability of the BPS. Enforcement staff reviews the registered entity's mitigating activities to ensure that the entity corrects the noncompliance and prevents recurrence. Enforcement staff also participates in settlement negotiations with the registered entity. If a registered entity challenges the findings of the violation and/or penalty, Enforcement staff would prosecute the case before the Board Compliance Committee, which acts as SERC's hearing body. SERC's processing of possible violations has improved because of increased resources and improved tools such as FFT and the SNOP filing mechanisms.

b. SERC has established rules that:

i. **Assure its independence of the users and owners and operators of the bulk-power system, while assuring fair stakeholder representation in the selection of its directors and balanced decision-making in any ERO committee or subordinate organization structure**. SERC's bylaws allow each SERC member company to appoint a director to SERC's board. The SERC Board Executive Committee is made up of 12 sector representatives from among the directors. All directors, alternate directors, and board committee representatives are required to comply with SERC's standards of conduct policy that prohibits participation in decisions that could pose a conflict of interest.

SERC's bylaws establish voting rules that ensure that no two sectors are able to approve a decision and that no one sector can veto a decision. These voting rules assure SERC's independence of the users, owners, and operators of the BPS. In addition, SERC has adopted the NERC CMEP, Appendix 4C to the NERC ROP, which provides fair and impartial procedures for the monitoring and enforcement of Reliability Standards. In addition, SERC employees and contractors sign non-disclosure and confidentiality agreements and conflict of interest forms.

ii. **Allocate equitably reasonable dues, fees, and other charges among end users for all activities**. SERC develops a budget annually that will accomplish all delegated duties. The budget is reviewed and approved by SERC's board before going to NERC and FERC. The budget is paid by all registered entities based on their proportionate share, based on the NEL. Pursuant to §202 of the NERC ROP, NEL is the net generation of an electric

system plus energy received from others less energy delivered to others through interchange. It includes system losses but excludes energy required for the storage of energy at energy storage facilities. Each entity reports the energy generated on an annual basis for the previous year. After verification by SERC, this data is provided to NERC. NERC produces an allocation of the budgets to each appropriate region.

iii. **Provide fair and impartial procedures for enforcement of reliability standards through the imposition of penalties**. SERC has adopted without exception the NERC CMEP, Appendix 4C to the NERC ROP, and the associated *Sanction Guidelines*, ROP Appendix 4B, which provide fair and impartial procedures for the enforcement of Reliability Standards within the SERC region. SERC maintains a *Conflict of Interest Policy* to ensure the integrity and independence of its compliance and enforcement staff. To ensure consistency and remain fair, unbiased and balanced in assessing penalties, SERC follows the *Sanction Guideline*s of NERC, utilizes the NERC penalty tool to develop a proposed penalty, and compares the proposed penalty with similarly situated violations that have been filed with and approved by FERC. All proposed penalties are reviewed and approved by a technical peer group, legal counsel, the director of enforcement, and the SERC CEO or vice president.

iv. **Provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing reliability standards and other exercising its duties**. The SERC RRSDP requires SERC to provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in development reliability standards.

SERC provides for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in its CMEP activities. A registered entity has the right to receive notice when it is placed on the NCR, and may appeal its registration to NERC and to the Commission.

The CMEP requires SERC to provide notice to a registered entity when it determines that the Registered Entity has violated a Reliability Standard, and the registered entity has an opportunity to respond. If a registered entity wishes to contest an alleged violation of a Reliability Standard or a penalty, it may request and receive a hearing, and may appeal the hearing decision to NERC. A registered entity also has the right to request a hearing to contest a twice-rejected mitigation plan or a remedial action directive.

At the conclusion of an enforcement matter, NERC publicly files a NOP with the Commission, which promotes openness and the opportunity for public comment. The ERO balances the interest in openness with the concern for the

security of critical infrastructure information, and as such, all sensitive critical infrastructure information is redacted from all public NOP filings.

v. **Provide for taking appropriate steps to gain recognition in Canada and Mexico**. The SERC region does not extend into any part of Canada or Mexico. Thus SERC has no need to establish rules that provide for taking appropriate steps to gain recognition in Canada or Mexico.

3. **SERC operates under a delegation agreement that promotes effective and efficient administration of bulk-power system reliability**. On January 1, 2011, SERC executed an amended and restated regional Delegation Agreement with NERC, which delegated to SERC certain activities pursuant to FPA §215. FERC approved this Delegation Agreement on June 12, 2012. These delegated activities include: (i) certification of BPS entities; (ii) registration of owners, operators, and users of the BPS responsible for compliance with the requirements of Reliability Standards; (iii) reliability assessment and performance analysis; (iv) event analysis and reliability improvement; (v) training and education; (vi) situational awareness and infrastructure security; (vii) the development and proposal of Reliability Standards to NERC; (viii) monitoring of compliance with Reliability Standards; and (ix) enforcement of compliance with Reliability Standards. These delegated activities are necessary for the effective administration of BPS reliability. SERC only performs those activities delegated to it under the Delegation Agreement.

Southwest Power Pool Regional Entity (SPP RE)

1. **SPP RE "is governed by an independent board, a balanced stakeholder board or a combination independent and balanced stakeholder board**." SPP RE is governed by three independent Regional Entity trustees. These trustees have autonomy over decisions in fund allocation and SPP RE budget approval, as well as oversight of SPP RE decisions on regional standards, compliance enforcement actions, and penalties. SPP RE's general manager reports directly to the SPP RE trustees. Only the trustees and certain SPP RE staff members have authority to make compliance and enforcement decisions.

2. **SPP RE met the requirements of Section 215 (c)(1)(2) of the Federal Power Act, because:**
   a. **SPP RE is able to develop and enforce reliability standards that provide for an adequate level of reliability of the bulk power system**. SPP RE is not actively developing any reliability standards at this time; however, it does have a RRSDP if the need for such standards were to arise.[152] The RRSDP allows for a fair and open process for adoption, approval, revision, reaffirmation, and deletion of a regional Reliability Standard. Due process is the key to ensuring that the Reliability Standards are developed in an environment that is equitable, accessible and responsive to the requirements of all interested and affected parties. SPP RE supports development of continent-wide

[152] *SPP RE Regional Reliability Standards Development Process Manual* (SPP RRSDP Manual), version 0 became effective October 2, 2007. A petition, in Docket No. RR14-1-000, to update the SPP RRSDP manual was filed by NERC with FERC on December 20, 2013. A 10-day comment period ended on January 10, 2014 with no comments being received.

Reliability Standards at NERC and any regional Reliability Standard developed by SPP RE will go beyond, add detail to, or cover matters not addressed in the NERC Reliability Standards.

Moreover, SPP RE is able to enforce reliability standards by the implementation of the CMEP. Illustratively, during the assessment period, SPP RE experienced a dramatic reduction in the average time to process violations to completion, a dramatic increase of self-reported violations, a dramatic reduction in average time for issuance of final on-site compliance audit reports, and a dramatic reduction in average time for issuance of a notice of possible violation (NPV). Specifically, prior to January 1, 2009, SPP RE's average time to process alleged violations to completion was 24 months, compared to 9.2 months during 2013. In 2009, only 3.1 % of incoming possible violations came from either self-reports or self-certifications, compared to 68.4% in 2013. In 2008, the average time to issue a final on-site compliance audit report to registered entities was 152 days, compared to 54 days during 2013. Prior to January 1, 2009, the average days for SPP RE to issue an NPV was 20.5 days, compared to 3.6 days in 2013.

b. SPP RE has established rules that:

i. **Assure its independence of the users and owners and operators of the bulk-power system, while assuring fair stakeholder representation in the selection of its directors and balanced decision-making in any ERO committee or subordinate organization structure**. SPP is governed by an independent board of directors and has an extensive organizational group structure comprised of stakeholders that represent the membership's diversity. SPP's bylaws provide for fair stakeholder representation and balanced decision-making. SPP RE does not have a separate committee structure or bylaws; however, it is an independent unit of SPP. and reports to its Regional Entity Trustees (SPP RE Trustees). In addition, SPP RE's employees are subject to standards of conduct, its employees and contractors are screened for conflicts of interest, and its compliance monitoring teams must agree to maintain strictly the confidentiality of their auditing efforts.

ii. **Allocate equitably reasonable dues, fees, and other charges among end users for all activities**. SPP RE follows the common assumptions developed by NERC and the Regional Entities to guide its budget projections. As such, SPP RE allocates projected statutory costs to end users via an annual assessment fee based on the SPP RE's registered entity's NEL. At the end of each budget cycle, a reserve balance is determined by taking the difference between the monies collected from end users through the assessment fee and the statutory costs incurred. This reserve balance is then used to offset the next year's funding requirement in addition to any penalty monies received during a twelve-month period. The annual assessment fee is adjusted at the beginning of each budget year (January 1).

iii. **Provide fair and impartial procedures for enforcement of reliability standards through the imposition of penalties**. The following, generally

describes the steps the SPP RE enforcement attorneys follow for penalty determinations, which are outlined in SPP RE's internal processes and procedures:

Step 1: Utilizing the NERC penalty determination framework tool (Penalty Tool), the enforcement attorney determines a suggested penalty amount for the violation. Note: Although not procedurally codified, once the SPP RE enforcement attorney member has calculated a preliminary penalty via the Penalty Tool, the enforcement attorney compares the proposed penalty (when possible) with similarly situated previous violations that have been filed and subsequently approved by FERC. Furthermore, enforcement attorneys implement guidance from *Sanction Guidelines*, ROP Appendix 4B, the NERC CMEP, ROP Appendix 4C, and FERC orders as to how the enforcement attorneys should assess factors such as load loss and repeat/similar/affiliate violation history.

Step 2: The enforcement attorney submits its proposed penalty amount, the Penalty Tool, notice(s) of alleged violation and proposed penalty or sanction and/or settlement documents, and any other information relevant to the proposed penalty to the sanctions review team (SRT), which consists of the SPP RE general manager, the manager of enforcement, and the director of compliance.

Step 3: The SRT reviews the information presented by the enforcement attorney and collectively either approves the proposed penalty amount or determines the appropriate penalty amount for the violation or violations. **Note:** Penalties in excess of $250,000 are required by procedure to receive additional approval of the SPP RE Trustees.

iv. **Provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing reliability standards and otherwise exercising its duties**. The SPP RE RRSDP includes steps for a fair and open standards process that is open to all regional stakeholders. Any entity within the SPP RE or SPP RTO region has a right to participate by: (a) expressing a position and its basis; (b) having that position considered; (c) voting through a segment-weighted balanced process; and (d) having the right to appeal.

v. **Provide for taking appropriate steps to gain recognition in Canada and Mexico.** This criterion does not apply to SPP RE.

3. **SPP RE operates under a delegation agreement that promotes effective and efficient administration of bulk-power system reliability**. The Delegation Agreement between SPP RE and NERC grants SPP RE the authority to carry out certain statutory activities, including: (i) certification of BPS entities; (ii) registration of owners, operators, and user of the BPS as responsible for compliance with requirements of Reliability Standards; (iii) reliability assessment and performance analysis; (iv) event analysis and reliability improvement; (v)

training and education; and (vi) situational awareness and infrastructure security. This delegation of authority has promoted the effective and efficient administration of the BPS. Through its delegated authority from NERC, SPP RE has successfully implemented the NERC CMEP, and is working with NERC and the other Regional Entities to improve both the effectiveness and efficiency of the program. As evidence of the success of the early program, SPP RE's region successfully navigated nine consecutive quarters without a reportable transmission vegetation contact.

SPP RE has also, in combination with the other Regional Entities and NERC, greatly enhanced the functionality of the electronic tool (webCDMS), used by registered entities to report compliance issues. Enhancements to webCDMS have allowed both the Regional Entities and registered entities to realize efficiency gains through the automation of processes such as: (i) self-reports, (ii) self-certifications, (iii) submission of mitigation plans, (iv) exchange of mitigation information, (v) mis-operations reporting, (vi) analysis of prior violations, and (vii) violation processing in general. Furthermore, the SPP RE compliance audit teams utilize a risk-based assessment to determine the scope of the compliance audit, and adjust the scope of compliance audits based on violation history and the particular risk presented by certain registered functions. To further improve the effectiveness and efficiency of the program going forward, SPP RE is working with NERC and the other Regional Entities to shift the focus of the ERO Enterprise to those areas of the BPS that present the greatest risk to reliability. To that extent, SPP RE is an active participant in the RAI process.

In addition, since January 1, 2009, SPP RE has steadily increased its outreach efforts. SPP RE has held annual workshops since 2009 and attendance has increased each year. SPP RE staff has made incremental improvements to the workshops, such as inviting more guest speakers from outside the SPP RE footprint including FERC Commissioners, NERC Board members, and Department of Homeland Security staff, adding break-out sessions to give registered entities a smaller setting to ask questions and voice concerns, and refining both advance and on-site preparations to ensure the workshops run smoothly and on-time. In 2011, workshop attendees began providing feedback via evaluation forms following the workshops; feedback has generally been very favorable. In 2011, SPP RE began publishing monthly newsletters and implemented an e-news format that is easily readable on handheld devices. In 2012, SPP RE created a video training webpage and began filming and publically posting training videos in-house and at workshops. The feedback from the training videos has been generally positive and benefits not only registered entities in the SPP RE footprint, but registered entities across all Regional Entities.

Texas Reliability Entity, Inc. (TRE or Texas RE)

1. **TRE "is governed by an independent board, a balanced stakeholder board or a combination independent and balanced stakeholder board**." Texas RE currently has a combination independent and balanced stakeholder board. From 2007 to 2010, the Regional Entity for the ERCOT region was Texas Regional Entity, Inc., an independent division of the Electric Reliability Council of Texas, Inc. (ERCOT, the ISO for the region). During that time, Texas RE shared the same board of directors as ERCOT ISO.

To ensure that the Regional Entity would remain independent from all registered entities, including ERCOT, a new Texas non-profit corporation called Texas Reliability Entity, Inc. (Texas RE), was formed to take over the functions as Regional Entity effective July 1, 2010. As part of this process, Texas RE separated its board of directors from ERCOT ISO. Texas RE is now governed by a combination independent and balanced stakeholder board consisting of nine members: (i) four independent directors; (ii) two industry-affiliated directors; (iii) the Texas RE CEO; and (iv) two ex-officio non-voting directors (the Public Utility Commission of Texas Chairman or delegate, and the Public Counsel from the Office of Public Utility Counsel). The independent directors are elected by Texas RE membership to serve staggered three-year terms. The two-industry-affiliated directors may not be from the same market sector and may not concurrently serve on the ERCOT ISO board of directors.

2. **TRE met the requirements of Section 215 (c)(1) (2) of the Federal Power Act, because**:
   a. **TRE is able to develop and enforce reliability standards that provide for an adequate level of reliability of the bulk power system.** Texas RE follows the requirements as defined by the NERC ROP, including the CMEP, and by the Delegation Agreement with NERC, including TRE's current RRSDP, and has used these documents to develop standards and to audit and enforce compliance with the standards.

      Standards Development: Texas RE participates in the NERC Standards Committee and develops, comments and votes on Reliability Standards. Texas RE also hosts quarterly meetings of the Reliability Standards Committee (RSC) and twice-monthly meetings of the NERC Standards Review Subcommittee (NSRS). Changes and proposed changes to NERC Reliability Standards are discussed in these forums. Texas RE created one major regional Reliability Standard (BAL-001-TRE) and several minor regional Reliability Standards (CIP-001 regional variance and IRO-0006-TRE) designed to improve reliability. The major regional Reliability Standard, BAL-001-TRE, was designed to maintain Interconnection steady-state frequency within defined limits in the ERCOT region. It requires individual generation facilities to operate with properly configured governors in service to meet frequency response performance requirements.

      Compliance: Between January 1, 2009 and December 31, 2013, Texas RE successfully completed more than 260 audits of registered entities for compliance with Reliability Standards. Texas RE uses the complete list of NERC-approved actively monitored Reliability Standards and Requirements as the minimum audit scope. Audit staff also investigates possible violations of the Reliability Standards arising from BPS disturbances, outages, self-reports, and complaints. Texas RE requires all Compliance employees, not just the auditors, to complete NERC scheduled basic training classes for auditors so that all employees have an understanding of the significance of the auditing process. In addition, Texas RE has developed a robust CIP compliance and audit program. All current CIP auditors have earned Department of Defense 8570 recognized certifications (e.g., CISSP, CEH, CISA, and Network+).

Enforcement: In addition to the auditing program, Texas RE has implemented a separate Enforcement program with a dedicated staff. The Enforcement group processes alleged violations originating from audits, spot checks, self-certifications, complaints, and self-reports. This includes managing settlement negotiations, supporting legal staff in contested case hearings, and reviewing and approving mitigation plans. Texas RE has been successful in streamlining the Enforcement process since 2009 by implementing a new webCDMS data management system and implementing new processes such as the FFT program.

b. TRE has established rules that:

i. **Assure its independence of the users and owners and operators of the bulk-power system, while assuring fair stakeholder representation in the selection of its directors and balanced decision-making in any ERO committee or subordinate organization structure.** Texas RE has adopted bylaws to assure its independence from industry while assuring fair stakeholder representation in selection of its directors and balanced decision-making in its committees. Its bylaws first provide that Texas RE membership is voluntary and open to any entity that is a user, owner or operator of the ERCOT region BPS that registers as a member with Texas RE and complies with Texas RE bylaws. In addition to the structure of the board described earlier, independent directors and members of their immediate families or households may not: (1) have current or recent status (within the past two years) as a director, officer or employee of an ERCOT region NERC registered entity or ERCOT region electric Market Participant, or (2) have direct business relationships, other than as customers, with any NERC registered entity or ERCOT region electric Market Participant. The industry-affiliated directors are selected annually by the Texas RE Member Representatives Committee and each must come from a different Texas RE membership sector: System Coordination and Planning, Transmission and Distribution, Cooperative, Municipal Utility, Generation, or Load-Serving and Marketing. The Texas RE bylaws prohibit an entity from belonging to any two membership sectors, and require the board of directors and any of its committees to operate using balanced decision-making.

ii. **Allocate equitably reasonable dues, fees, and other charges among end users for all activities.** Texas RE bylaws and its Delegation Agreement with NERC provide that it will allocate equitably reasonable dues, fees, and other charges among end users for its statutory activities. Each year Texas RE produces a draft budget using templates provided by NERC, and posts the draft on its website for public comment. The budget includes the costs necessary to perform Texas RE's statutory functions under the Delegation Agreement with NERC and any expected income, such as membership fees. The budget is reviewed for reasonableness by the Texas RE Member Representatives Committee and approved by the Texas RE board of directors, NERC and FERC. Pursuant to Exhibit E to

its Delegation Agreement, assessments to fund Texas RE delegated functions and related activities are allocated to all load-serving entities in the region on the basis of NEL. Penalty monies received by Texas RE are applied as a general offset to its budget requirements for the subsequent fiscal year.

iii. **Provide fair and impartial procedures for enforcement of reliability standards through the imposition of penalties.** Texas RE has adopted and implemented the CMEP in accordance with its Delegation Agreement with NERC. Texas RE is committed to five guiding principles: (1) independence; (2) ethics and integrity; (3) inclusiveness; (4) fairness and openness; and (5) organizational effectiveness and efficiency. Texas RE strives to be fair, unbiased and balanced in its enforcement actions and imposition of penalties, and its internal procedures incorporate these concepts. After a possible violation is found by the Compliance group, the violation is reviewed and verified by a member of the Enforcement group. Penalties are calculated using the NERC *Sanction Guidelines* and are reviewed in relation to similar penalties assessed in this and other regions. In addition, all penalties are reviewed by the director of enforcement prior to issuance.

Texas RE also has implemented policies and procedures to ensure its employees act with independence, ethics, integrity, fairness, and openness. All Texas RE employees and contractors must annually sign an ethics agreement which requires them to conduct Texas RE business with total objectivity and to avoid situations in which his or her personal or financial interests conflict or appear to conflict with the interests of Texas RE. A conflict of interest arises when: (1) the personal, financial, or other interest of a Texas RE employee is significantly affected or may reasonably appear to be affected by the employee's actions or decisions in the employee's capacity at Texas RE; or (2) the action of any employee is in any way detrimental to the best interests of Texas RE. Financial interest includes any ownership, investment, or compensation interest by the employee or a member of the employee's household, and specifically includes any direct or indirect remuneration, as well as gifts or favors which are not insubstantial. An employee must immediately inform the Texas RE legal department if a conflict of interest or even the appearance of a conflict of interest might exist, to allow Texas RE management to evaluate the situation. After full disclosure by the employee, Texas RE management may agree to conditions that appropriately limit any potential influence from a conflict of interest.

Texas RE also follows the CMEP requirement to provide biographies of all potential audit team members to registered entities prior to a Compliance engagement and provide opportunity for entities to object to use of any employee where a potential conflict of interest exists. At the

end of each audit, registered entities are also provided a questionnaire which allows them to directly report to NERC any concerns they have with fairness, openness, or objectivity with respect to how Texas RE conducted the audit. In addition, Texas RE has implemented a Compliance hotline to allow anyone to report (anonymously if desired) any noncompliance by a registered entity and any ethics complaints they have concerning Texas RE.

iv. **Provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing reliability standards and otherwise exercising its duties**. As part of its Delegation Agreement, Texas RE has adopted and follows a RRSDP designed to provide for reasonable notice and opportunity for public comment, due process, and balancing of interests. The RRSDP requires that proposed Reliability Standards must be drafted by a standards drafting team and be posted publicly, and it requires a public comment period prior to any vote on the standard by Texas RE membership.

Texas RE also conducts its general operations in a manner that is transparent to the public. As required by its bylaws, it posts public notices of its board and committee meetings on its public website and posts meeting materials, including draft budgets, for public review prior to the meetings. The Texas RE public website includes training materials, useful compliance information, and the contact information for key Texas RE personnel.

Texas RE also provides due process to registered entities seeking to contest a violation, penalty or sanction. Texas RE adheres to the NERC ROP and CMEP, which require Regional Entities to provide registered entities reasonable notice of possible violations, the ability to contest a violation or penalty or sanction, and the ability to appeal such matters to the NERC Compliance Committee and FERC. In August 2013, FERC approved Texas RE's request to begin using the same hearing procedures as are used by the other seven Regional Entities.

v. **Provide for taking appropriate steps to gain recognition in Canada and Mexico.** This criterion is not applicable to Texas RE.

3. **TRE operates under a delegation agreement that promotes effective and efficient administration of bulk-power system reliability**. Under its Delegation Agreement with NERC, Texas RE has promoted effective and efficient administration of the BES in the ERCOT region. Texas RE has worked with industry to create a major regional Reliability Standard (BAL-001-TRE) and several minor regional Reliability Standards (CIP-001 regional variance and IRO-006-TRE) designed to improve reliability in the ERCOT region. The major regional Reliability Standard requires individual generation facilities to operate with properly configured governors in service to meet frequency

response performance requirements. Texas RE also has successfully implemented the CMEP in the region, performing more than 260 audits since January 2009 and developing a robust CIP audit program. Since 2009, Texas RE has streamlined its Enforcement processing by implementing the webCDMS data management system in 2011 and implementing the FFT program to more quickly process lower risk violations. From 2010 to 2012, Texas RE also worked in cooperation with NERC, the other regions and industry to develop an events analysis program in which registered entities report their performance during system events and develop lessons learned to be shared with the industry. Early in the program, when Texas faced rotating outages during the 2011 Southwest Cold Weather Event, Texas RE used the framework the events analysis program provided to quickly collect and analyze information from the event and to disseminate it to FERC, NERC, and the industry.

Western Electricity Coordinating Council (WECC)

1. **WECC "is governed by an independent board, a balanced stakeholder board or a combination independent and balanced stakeholder board**." Since its creation, WECC has been governed by a hybrid board of directors including both non-affiliated directors and a balanced group of stakeholder directors as envisioned by the FPA §215(e)(4), 16 U.S.C. §824o(e)(4). However, on June 27, 2013, the WECC Board approved the bifurcation of the company into a Regional Entity (WECC) and a Reliability Coordination Company, Peak Reliability. This decision—the culmination of a year of work by various WECC board committees, staff, WECC members, and WECC stakeholders—signals a major landmark in the history of the organization. Under this new structure the RC and IA functions in the Western Interconnection will become a separate company from WECC. When established, Peak Reliability will provide core and other associated reliability coordination services within the Western Interconnection. As anticipated, the Commission approved the relevant documents by the end of December 2013;[153] however, as there were outstanding compliance filings, the bifurcation was not finalized during the assessment period.[154] Nevertheless, WECC and Peak Reliability began operating as separate entities in many respects by that time.

2. **WECC met the requirements of Section 215 (c)(1) (2) of the Federal Power Act, because**:
    a. **WECC is able to develop and enforce reliability standards that provide for an adequate level of reliability of the bulk power system**. WECC's authority to enforce Reliability Standards is based on the authority granted in its Delegation Agreement with NERC. FERC's approval of the Delegation Agreement conferred authority to WECC to manage and enforce compliance with FERC-approved Reliability Standards and to apply penalties up to the extent of FERC's civil penalty

[153] *See Western Electricity Coordinating Council*, Order on Petition for Declaratory Order, 143 FERC ¶ 61,239, *order on reh'g*, 145 FERC ¶ 61,202 (2013), *appeal pending sub nom. Edison Electric Institute v. FERC*, No. 14-1012 (D.C. Cir. Jan. 27, 2014).

[154] The Commission accepted the compliance filings on February 12, 2014. *See North American Electric Reliability Corporation; Western Electricity Coordinating Council*, 146 FERC ¶ 61,092 (2014), *order on reh'g*, 147 FERC ¶ 61,063 (2014), *appeal pending sub nom. Edison Electric Institute v. FERC*, No. 14-1071 (D.C. Cir. May 9, 2014).

authority. Additionally, WECC develops Regional Criteria and practices to improve the functioning and efficiency of the Western Interconnection. This combination provides a forum for addressing system-wide issues and an oversight role to promote reliable operation of the Western Interconnection.

WECC also demonstrated its ability to enforce reliability standards during the assessment period, by successfully clearing its backlog of Enforcement work; completing all audits contemplated in its annual Implementation Plans; developing and maintained highly qualified Compliance staff; enhancing, streamlining and documenting all the Enforcement processes; successfully implementing new IT solutions and systems; and expanding and enhancing its compliance encouragement and outreach efforts. Furthermore, WECC worked collaboratively with the other Regional Entities and NERC to bring forward the Omnibus proposal; proposed NERC ROP changes to streamline TFE processing; developed new registration system tools; and, actively participated in several ongoing NERC IT projects, lending expertise and practical experience.

b. WECC has established rules that:

i. **Assure its independence of the users and owners and operators of the bulk-power system, while assuring fair stakeholder representation in the selection of its directors and balanced decision-making in any ERO committee or subordinate organization structure**. WECC currently has a hybrid board comprised of member class directors and non-affiliated (independent) directors, who are subject to standards of conduct set out in WECC's bylaws. This ensures that member/stakeholder views are well-represented and that board decisions are ultimately made fairly and in the best interests of WECC as a whole. Effective January 1, 2014, WECC transitioned to an all independent director board. Accordingly, directors are directly elected by the WECC membership and members are represented on a newly created Member Advisory Committee that has direct access to the WECC Board to provide advice and recommendations regarding WECC policy and proposed board decisions. In addition, WECC staff members, and representatives from WECC member entities, routinely participate in ERO and ERO Enterprise committees and work groups.

ii. **Allocate equitably reasonable dues, fees, and other charges among end users for all activities**. The allocation of dues, fees and other charges is governed by §12.1 of the WECC bylaws, Funding of Reliability Activities. WECC funds all activities undertaken pursuant to FPA §215 in accordance with the funding provisions and procedures of that law and related FERC regulations and orders. The WECC Board approves the annual business plan and budget in time for submission to the ERO and to FERC for approval. WECC funds reliability activities undertaken pursuant to any agreements with appropriate Canadian or Mexican authorities in accordance with the provisions of those agreements. In adopting budgets for the costs of reliability activities, the WECC Board seeks an equitable allocation based upon the NEL

and other relevant factors consistent with applicable law, the Delegation Agreement and any international reliability agreements. To the extent that WECC elects to fund any activities not eligible for funding pursuant to §§12.1.1 and 12.1.2, it does so through the use of service fees, charges or dues applicable to the persons or entities that voluntarily participate in such activities.

iii. **Provide fair and impartial procedures for enforcement of reliability standards through the imposition of penalties.** WECC's Delegation Agreement with NERC is based on the NERC *pro forma* Delegation Agreement and has been reviewed and approved by FERC. As required, WECC developed an annual CMEP Implementation Plan, which identifies the NERC Reliability Standards on the actively monitored list as well as the compliance monitoring methods that will be used to enforce those standards. The plan was submitted to NERC for approval. Additionally, WECC has developed and documented all formal processes and procedures relating to enforcement activities, including penalties. In this regard, WECC uses the NERC *Sanction Guidelines* as a framework for assessing fair and reasonable penalties, and considers all facts associated with the registered entity and the alleged violation. Individuals responsible for assessing, recommending, or negotiating penalties are not otherwise involved in compliance monitoring or discovery of violations. In other words, WECC specifically segregates the duties associated with violation discovery or review and violation disposition and penalty assessment. Furthermore, WECC has a layered review approach to penalties, including non-monetary ones. Specifically, the manager of enforcement policy reviews all penalties and communicates with the director of enforcement, who then reviews and, as appropriate, approves them. WECC management reviews these processes and procedures bi-annually. Finally, WECC's enforcement staff receives regular training on all aspects of their duties to ensure consistency of application. This training is delivered in weekly staff meetings as well as at formal training sessions held at least annually.

iv. **Provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing reliability standards and otherwise exercising its duties.** WECC uses the FERC-approved WECC RRSDP to develop regional Reliability Standards along with regional criteria and regional business practices. These procedures assure that the documents will be developed in a fair and open manner with contribution and review by subject matter experts and that all affected parties will have the chance to comment and vote on the documents. Illustratively, proposed standards are drafted by a standards drafting team, publicly posted, and subject to a mandatory public comment period prior to any vote.

In regard to the exercise of its other duties, WECC posts on its website notices of, and agendas and materials for, board and committee meetings. WECC

also adheres to the NERC ROP and the CMEP processes, which provide due process protections to registered entities with respect to compliance obligations and enforcement of standards violations. Accordingly, registered entities are provided reasonable notice of possible violations, and the right to contest a violation, penalty or sanction, and to appeal the Regional Entity's decisions to the NERC Board of Trustees Compliance Committee, and the Commission.

v. **Provide for taking appropriate steps to gain recognition in Canada and Mexico**. WECC has negotiated various agreements with the applicable governmental authorities for British Columbia, Canada, Alberta, Canada, and Baja, Mexico, the three international areas included in the Western Grid, as detailed below:

British Columbia:

Under the Administration Agreement (dated October 8, 2009) between the British Columbia Utilities Commission (BCUC) and the WECC, WECC acts as the administrator for the BCUC in carrying out certain activities relating to the Mandatory Reliability Standards program in British Columbia. Working under this agreement, WECC monitors compliance to the standards adopted in BC. WECC receives and reviews self-reports, self-certifications, and periodic data submittals; conducts audits; and reviews mitigation plans and other such activities. At the BCUC's request, WECC has set up a separate webCDMS portal, an electronic system to collect compliance data, dedicated to BCUC and its entities.

Alberta:

WECC acts as the Compliance Monitor for the Alberta Market Surveillance Administrator (Alberta MSA), under the Services Agreement (dated April 30, 2010) between the Alberta MSA and WECC, in carrying out certain activities related to Alberta Reliability Standards, specific to the Alberta Electric System Operator (AESO), in Alberta, Canada. WECC operates under the Services Agreement with the MSA, and as contemplated in the membership and operating agreement (MOA) (dated September 23, 2008) with the AESO.

Mexico:

Under the MOA (dated December 31, 2010) between Comisión Federal de Electricidad (CFE) and WECC, WECC acts as CFE's compliance monitor for certain activities in Baja California, Mexico, monitoring compliance with its mandatory Reliability Standards. The agreement between CFE and WECC requires that WECC not disclose any confidential data to anyone other than CFE. Any request from NERC or FERC to WECC for data relating to WECC activities in Mexico is directed to CFE. The CFE/WECC annual Implementation Plan, based on WECC's

recommendations and after consultation with the Area de Control Baja California (ACBC), CFE's compliance program administrator, includes a list of actively monitored standards, a description of the monitoring methods WECC uses for designated entities, and the compliance audit timeline. As with British Columbia, the Alberta MSA, and the AESO, WECC set up a separate webCDMS portal for use by CFE.

In summary, WECC does not have enforcement or registration authority for any of the international jurisdictions within the Western Interconnection. WECC provides monitoring, reviews mitigation plans and completed mitigation plans, and assessment recommendations with respect to alleged violations.

3. WECC operates under a delegation agreement that promotes effective and efficient administration of bulk-power system reliability. WECC assures the reliability and efficient administration of the Western Interconnection through a variety of activities authorized under its Delegation Agreement. To start with, during the assessment period, WECC continued to develop regional Reliability Standards, in large part due to its unique situation among the Regional Entities. Indeed, WECC has developed the most regional Reliability Standards because of a mandatory program it had in place prior to the approval of NERC as the ERO and the delegation to WECC. Under this program (called the Reliability Management System (RMS)), WECC is required to translate existing reliability criteria into regional mandatory standards. As a consequence, whereas all of the other Regional Entities have a total of seven regional Reliability Standards, WECC alone has a total of eight.[155]

WECC likewise promoted effective and efficient administration of the BPS in the Western Interconnection during the assessment period through its implementation of NERC's CMEP approved by the Commission. Illustratively, WECC successfully cleared its backlog of Enforcement work; completed all audits contemplated in its annual Implementation Plans; developed and maintained a highly qualified Compliance staff; enhanced, streamlined and documented all the Enforcement processes; successfully implemented new IT solutions and systems; and expanded and enhanced its compliance encouragement and outreach efforts. Furthermore, WECC worked collaboratively with the other Regional Entities and NERC to bring forward the Omnibus proposal; proposed ROP changes to streamline TFE processing; developed new registration system tools; and, actively participated in several ongoing NERC IT projects, lending expertise and practical experience.

As a separate matter with respect to the administration of the Western Interconnection, during the assessment period, WECC managed a comprehensive planning database, provided guidance on the analysis and modeling of the transmission system, and developed scenario

[155] These eight regional Reliability Standards are: (i) FAC-501-WECC-1 (Transmission Maintenance); (ii) VAR-002-WECC-1 (Automatic Voltage Regulators); (iii) VAR-501-WECC-1 (Power System Stabilizer); (iv) PRC-004-WECC-1 (Protection System and Remedial Action Scheme Misoperation); (v) IRO-006-WECC-1 (Qualified Transfer Path Unscheduled Flow Relief); (vi) BAL-004-WECC-01 (Automatic Time Error Correction); (vii) TOP-007-WECC-1 (System Operating Limits); and (viii) BAL-002-WECC-2 (Contingence Reserve) (replacing BAL-STD-002-2).

studies of system performance to establish operating policies and limits, and regional transmission planning. In addition, WECC performed annual assessments of 10-year loads and resources in the Western Interconnection and created a 10-year coordinated plan of system growth. WECC also provided information to NERC for their annual summer and winter assessments of the reliability of the BPS. Beginning in 2012, WECC produced an annual *State of the Interconnection* report to provide WECC's members and stakeholders with an independent assessment of data collected annually in the Western Interconnection. The goal was to develop reasonable measurements that would identify reliability trends in the Interconnection.

FEDERAL ENERGY REGULATORY COMMISSION
DOCKET NO. RR14-____

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

ATTACHMENT 3

TO

FIVE-YEAR ELECTRIC RELIABILITY ORGANIZATION PERFORMANCE ASSESSMENT REPORT

NERC ASSESSMENT OF REGIONAL ENTITY DELEGATED FUNCTIONS

JULY 21, 2014

Attachment 3

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This **Attachment 3** is NERC's assessment of the Regional Entities' performance of their delegated functions during the five-year assessment period 2009 through 2013. Following are brief descriptions of the geographic footprints of the eight Regional Entities.

Florida Reliability Coordinating Council, Inc. (FRCC) is the Federal Energy Regulatory (FERC or Commission)-approved Regional Entity for the territory covering peninsular Florida in the Eastern Interconnection.

Midwest Reliability Organization (MRO) is the FERC-approved Regional Entity for the north central region of North America within the Eastern Interconnection. MRO's footprint spans the states of North Dakota, Minnesota, and Nebraska, the majority of the territory in the states of South Dakota, Iowa, and Wisconsin, portions of Michigan and Montana, and the Canadian provinces of Saskatchewan and Manitoba.

Northeast Power Coordinating Council, Inc. (NPCC) is the FERC-approved Regional Entity for the northeastern North American region in the Eastern Interconnection. NPCC's footprint includes the states of Connecticut, Maine, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont, as well as the Canadian provinces of New Brunswick, Nova Scotia, Ontario, and Quebec.

ReliabilityFirst Corporation (ReliabilityFirst) is the FERC-approved Regional Entity for portions of the mid-Atlantic and east central areas of the United States within the Eastern Interconnection. ReliabilityFirst's footprint includes all or portions of the states of New Jersey, Pennsylvania, Delaware, Maryland, Virginia, West Virginia, Ohio, Michigan, Kentucky, Tennessee, Indiana, Illinois, Wisconsin, and the District of Columbia.

SERC Reliability Corporation (SERC) is the FERC-approved Regional Entity for the southeastern United States region within the Eastern Interconnection. SERC's footprint includes the states of Alabama, Georgia, Mississippi, Missouri, North Carolina, South Carolina, and Tennessee, and portions of the states of Arkansas, Florida, Illinois, Iowa, Kentucky, Louisiana, Oklahoma, Texas, and Virginia.

Southwest Power Pool Regional Entity (SPP RE) is the FERC-approved Regional Entity for the central southern United States within the Eastern Interconnection. SPP RE's footprint includes all or parts of the states of Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, and Texas. SPP RE is an independent and functionally separate division of Southwest Power Pool, Inc., one of nine independent system operators (ISOs)/RTOs in North America.

Texas Reliability Entity, Inc. (Texas RE) is the FERC-approved Regional Entity for the Electric Reliability Council of Texas (ERCOT) region in the Texas Interconnection. At the time of the three-year performance assessment, Texas Regional Entity, an independent division of ERCOT, performed compliance monitoring and enforcement activities for the ERCOT region. Texas RE was formed on January 1, 2010 to become the successor Regional Entity for the ERCOT region. Effective July 1, 2010, NERC delegated to Texas RE the authority and responsibility for

the continuation of all compliance monitoring and enforcement activities that it had previously delegated to Texas Regional Entity.

Western Electricity Coordinating Council (WECC) is the FERC-approved Regional Entity for the portions of the Western United States and Canada in the Western Interconnection. WECC's footprint extends from the provinces of Alberta and British Columbia in Canada to the northern portion of Baja California, Mexico. WECC's service territory includes all or portions of 14 states in the western United States. Geographically, WECC's territory is the largest of all the Regional Entities.

I. RELIABILITY STANDARDS DEVELOPMENT

Section 215(d) of the Federal Power Act (FPA), 16 U.S.C. §824o(d), requires NERC to develop mandatory and enforceable Reliability Standards that are subject to Commission review and approval. A Regional Entity may also develop a Reliability Standard for approval by NERC and by the Commission, to be effective in that Regional Entity only. The FPA and Commission regulations provide that the ERO shall rebuttably presume that a proposal from a Regional Entity organized on an interconnection-wide basis for a Reliability Standard or modification to a Reliability Standard to be applicable on an interconnection-wide basis is just, reasonable, and not unduly discriminatory or preferential, and in the public interest.[1] This presumption is also embodied in the Regional Delegation Agreements (RDAs), which delegate to each Regional Entity authority to propose regional Reliability Standards to NERC for approval.

In Order No. 672, the Commission stated that:

> As a general matter, we will accept the following two types of regional differences, provided they are otherwise just, reasonable, not unduly discriminatory or preferential and in the public interest, as required under the statute: (1) a regional difference that is more stringent than the continent-wide Reliability Standard, including a regional difference that addresses matters that the continent-wide Reliability Standard does not; and (2) a regional Reliability Standard that is necessitated by a physical difference in the Bulk-Power System.[[2]]

These parameters are embodied in the NERC Rules of Procedure (NERC ROP). Section 312.1 of the NERC ROP specifies that Regional Entities may propose regional Reliability Standards that set more stringent reliability requirements than the NERC Reliability Standard or cover matters not covered by an existing NERC Reliability Standard. Section 313.1 of the NERC ROP specifies that Regional Entities may develop Regional Criteria that are necessary to implement, augment, or comply with NERC Reliability Standards, but which are not Reliability Standards; or which address issues not within the scope of Reliability Standards.

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[1] FPA §215(d)(3), 16 U.S.C. §824o(d)(3), 18 C.F.R. §39.5(b).

[2] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 291, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

Regional Reliability Standards must be approved by NERC and are then submitted by NERC to the Commission; they become enforceable as NERC Reliability Standards under §215 of the FPA in the U.S. once they are approved by the Commission. Therefore, regional Reliability Standards must meet the requirements set out by the Commission for approval of such standards, including having violation risk factors (VRFs) and violation severity levels (VSLs) that meet the criteria the Commission has set out in its various orders.

To evaluate each Regional Entity's performance during the assessment period, NERC focused on two parameters. First, NERC reviewed whether each Regional Entity has in place a regional Reliability Standards Development Procedure (RSDP) that meets applicable requirements. This portion of the evaluation was straightforward because, as described in §I.A below, each Regional Entity is required to have in place, as part of its RDA, a NERC-approved and Commission-approved RSDP that satisfies a pre-established set of attributes. During the assessment period, some of the Regional Entities developed revisions to their RSDPs, which were approved by NERC and by the Commission. Second, NERC reviewed each Regional Entity's activity, if any, in developing proposed regional Reliability Standards during the assessment period. As described in §I.B below, with the exception of WECC, the Regional Entities have, in general, suspended regional Reliability Standards development activities in favor of devoting resources and stakeholder participation to the development of, and reliance on, NERC's continent-wide Reliability Standards. However, during the assessment period, NPCC, ReliabilityFirst, SERC and Texas RE, in addition to WECC, had regional Reliability Standards approved by the Commission. The Regional Entities will continue to develop regional Reliability Standards only to the extent that NERC Reliability Standards do not address a perceived gap in reliability specific to a particular region.

A. Regional Entity Standards Development Processes

Exhibit C to each RDA contains (i) the list of NERC's common attributes of an appropriate RSDP, and (ii) each Regional Entity's current RSDP. In reviewing and approving a Regional Entity's RSDP for inclusion in Exhibit C to the RDA, NERC reviews the RSDP against the common attributes to determine whether the RSDP meets the common attributes. During the assessment period, some of the Regional Entities' RSDPs were revised and approved by NERC and then by the Commission.[3]

The RSDPs include the process that each Regional Entity uses to develop regional Reliability Standards that are proposed to NERC for adoption, and, where applicable, regional variances if the Regional Entity is organized on an interconnection-wide basis. While the RSDPs are not identical, each one must, as noted, satisfy the common attributes that advance the development of regional Reliability Standards consistent with the objective of a uniform reliability program. Among other things, participation in the development of a regional Reliability Standard must be open to all organizations that are directly and materially affected by the bulk power system (BPS) located in the Regional Entity's footprint, with no constraints based on financial capability, technical expertise or membership in the organization. The RSDP must provide for an appropriate

[3] NERC maintains on its website each Regional Entities' RSDP which lists the date of the current version. *See* http://www.nerc.com/pa/Stand/Pages/RegionalStandardsDevelopment.aspx.

balance of interests and the process must be structured so that it may not be dominated by any two interest categories and no single interest category can defeat a matter. All entities with a direct and material interest in the BPS in the Regional Entity may participate in the development of regional Reliability Standards by expressing a position and support for that position. Participating entities then will have that position considered and have the right to appeal the final outcome. The RSDP must also allow for reasonable notice and opportunity for public comment, and include language that states that all actions material to the development of any regional Reliability Standards be transparent.[4]

Based on its review and approval of the Regional Entities' RSDPs for inclusion in the RDAs and the subsequent approval by the Commission, NERC believes that during the assessment period, all of the Regional Entities met the requirements applicable to the ERO in the development of regional Reliability Standards.[5] Specifically, the Regional Entities: (i) demonstrated the ability to develop Reliability Standards that provide for an adequate level of reliability of the BPS; (ii) established rules that assure the independence of the users and owners and operators of the BPS, (iii) took action to ensure balanced decision-making in applicable committees or subordinate organization structures; and (iv) developed rules that provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing Reliability Standards. During the assessment period, each Regional Entity fulfilled the obligation to provide an open, fair, balanced, and inclusive process for the development of regional Reliability Standards, as demonstrated by the approval of those processes by NERC and the Commission.

B. Review of Each Regional Entity's Standards Development Activities During the Assessment Period

NERC focuses on the development of its continent-wide Reliability Standards as consistent with the goal of a reliable BPS. The Regional Entities have developed relatively few regional Reliability Standards to address unique situations with specific or more stringent requirements in a particular interconnection or geographic region which the NERC continent-wide standards may not address. Since the Commission issued Order No. 693 in 2007, approving the initial set of NERC continent-wide Operations and Planning Reliability Standards, the Commission has approved a total of only seven regional Reliability Standards submitted by Regional Entities other than WECC.

The Regional Entities are concentrating their standards development resources on working with NERC and stakeholders to develop clear, reasonable, and technically sound continent-wide Reliability Standards in a timely and efficient manner, and to ensure that regional concerns are addressed in the continent-wide Reliability Standards. This approach also avoids duplicating NERC's efforts at the regional level. Barring the existence of a perceived region-specific gap in reliability not addressed by NERC Reliability Standards, the Regional Entities will refrain from developing further regional Reliability Standards.

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[4] NERC maintains on its website a current overview of regional Reliability Standards under development, with detailed information on the status of the proceeding.
See http://www.nerc.com/pa/Stand/Pages/RegionalReliabilityStandardsUnderDevelopment.aspx.

[5] FPA §215(c)(1) and (2); 16 U.S.C. §824o(c)(1)(2).

To this end, the Regional Entities are actively encouraging awareness and participation by stakeholders in their respective areas in the NERC standards development process, by engaging in educational outreach efforts, and through participation in the NERC Standards Committee (NERC SC) and related subcommittees. The Regional Entities also have standards committees or similar groups at the regional level that analyze the draft ERO standards to determine their quality and effectiveness and evaluate whether the reliability objective is adequate and cost effective, and to provide input on these topics in the NERC standards development process.

The following subsections provide a review of the activities of each Regional Entity in the development of regional Reliability Standards during the assessment period.

1. Florida Reliability Coordinating Council, Inc.

The most recent version of the FRCC RSDP was approved by the Commission on June 12, 2012 and is included as Appendix C to the FRCC RDA. FRCC currently has no FERC-approved regional Reliability Standards or regional variances. During the assessment period, FRCC placed two regional Reliability Standards development projects on hold awaiting the completion of NERC standards development projects, and terminated one project because NERC's continent-wide Reliability Standard was determined to be sufficient for FRCC's reliability needs. Additionally, FRCC's registered ballot body and board of directors approved one project, which was held in abeyance while the adequacy of the NERC continent-wide Reliability Standard was evaluated, and will be withdrawn if it is determined to be sufficient for FRCC's needs. FRCC prefers the development of continent-wide Reliability Standards, but will follow its regional RSDP should a need arise for a more stringent standard or a standard to cover an area that NERC Reliability Standards do not.

2. Midwest Reliability Organization

MRO supports the development of continent-wide Reliability Standards to maintain the reliable operations of the BPS, as opposed to regional Reliability Standards, particularly in the Eastern Interconnection. Therefore, MRO decided during the assessment period to forego the development of regional Reliability Standards. Nevertheless, MRO has a regional RSDP in effect. The most recent revised version of the MRO RSDP was approved by the Commission on June 12, 2013[6] and is included as Appendix C to the MRO RDA. The principal purposes of these amendments to the MRO RSDP include: (i) to provide greater alignment of MRO's standards develop procedures with the NERC *Standard Processes Manual*; (ii) to incorporate a requirement for a review of the MRO RSDP every five years; and (iii) to provide various clarifications to the process development steps in the MRO RSDP. MRO also has a stakeholder-based Standards Committee comprised of subject matter experts (SMEs) in the event there is a need for a regional Reliability Standard in the future.

[6] *North American Electric Reliability Corporation*, Docket Nos. RR13-5-000 (June 12, 2013) (unpublished letter order).

3. Northeast Power Coordinating Council, Inc.

NPCC has developed a revised RSDP that provides a results-based, consensus building approach by which NPCC may develop regional Reliability Standards and Regional Variances proposals to the ERO for adoption, under delegated authority by the Commission and the Canadian Provincial regulatory and/or governmental authorities.

During the assessment period, NPCC developed a disturbance monitoring regional Reliability Standard, PRC-002-NPCC-01, to ensure that adequate disturbance data are available to facilitate event analyses. This NPCC regional Reliability Standard addresses a specific recommendation from the August 14, 2003 Blackout final NERC report regarding the use of time-synchronized data recorders.[7] Substantively, this NPCC regional Reliability Standard outlines the basic requirements for the type, location and capability of equipment to be placed on the BPS to enable analysis of grid disturbances to be conducted effectively and efficiently. This regional Reliability Standard is intended to establish enforceable and uniform requirements for disturbance monitoring throughout the NPCC region. On October 20, 2011, the Commission issued an order approving regional Reliability Standard PRC-002-NPCC-01, the related VRFs and VSLs, implementation plan, and two associated regional definitions in the *Glossary of Terms Used in NERC Reliability Standards* (NERC Glossary).

NPCC also developed regional Reliability Standard PRC-006-NPCC-1, Automatic Underfrequency Load Shedding, during the assessment period. The purpose of PRC-006-NPCC-1 is to provide a regional Reliability Standard that ensures the development of an effective regional automatic underfrequency load shedding (UFLS) program in order to preserve the security and integrity of the BPS during declining system frequency events, in coordination with the NERC UFLS Reliability Standard characteristics. Further, this NPCC regional Reliability Standard creates a region-wide and fully coordinating single set of UFLS requirements that will serve as a last resort to preserve the BPS during a major system failure that may cause a system frequency collapse. On February 21, 2013, the Commission issued Order No. 775 approving regional Reliability Standard PRC-006-NPCC-1, the related VRFs and VSLs, implementation plan, and the effective dates proposed by NERC.[8]

4. ReliabilityFirst Corporation

ReliabilityFirst has an approved RSDP in place as Exhibit C to its RDA. ReliabilityFirst no longer develops regional Reliability Standards, in order to avoid duplication with the NERC continent-wide Reliability Standards. However, ReliabilityFirst has proved its ability to develop regional Reliability Standards, as shown by its development of regional Reliability Standard BAL-502-RFC-02, Planning Resource Adequacy Analysis, Assessment and Documentation, during the assessment period. The purpose of this standard and associated definitions is to establish common criteria based on the principle of "one day in ten years" loss of load expectation for the analysis,

[7] *See Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* available at: http://www.nerc.com/pa/rrm/ea/Pages/Blackout-August-2003.aspx.

[8] *Regional Reliability Standard PRC-006-NPCC-1 – Automatic Underfrequency Load Shedding*, Order No. 775, 142 FERC ¶ 61,128 (2013).

assessment, and documentation of resource adequacy for load in the ReliabilityFirst footprint and to establish requirements for planning coordinators in the ReliabilityFirst region regarding resource adequacy assessment, a subject matter not addressed in NERC's continent-wide Reliability Standards. The Commission approved regional Reliability Standard BAL-502-RFC-02 and related filings in an order issued on March 17, 2011, directing that the regional Reliability Standard and associated VSLs, VRFs, and definitions become effective on the date of that order.[9]

5. SERC Reliability Corporation

The SERC RSDP, included in Exhibit C to the SERC RDA, defines the process for the development, revision, reaffirmation, and withdrawal of SERC regional Reliability Standards. The SERC RSDP requires any proposed SERC regional Reliability Standard to be more stringent than a continent-wide Reliability Standard, whether the regional Reliability Standard addresses matters that the continent-wide Reliability Standard does not or the regional Reliability Standard is necessitated by a physical difference in the BPS within the SERC region. SERC regional Reliability Standards are required to provide for as much uniformity as possible with continent-wide Reliability Standards.

SERC has one Commission-approved regional Reliability Standard, PRC-006-SERC-01, Automatic Underfrequency Load Shedding Requirements. The purpose of this standard and the associated VSLs and VRFs is to establish consistent and coordinated requirements for the design, implementation, and analysis of automatic UFLS schemes among all applicable entities within the SERC region so that distribution providers and transmission owners may effectively mitigate the consequences of an underfrequency event. The standard effectively mitigates the consequences of an underfrequency event while accommodating differences in system transmission and distribution topology among SERC planning coordinators. The Commission approved regional Reliability Standard PRC-006-SERC-01 in Order No. 772 issued on December 20, 2012.[10]

SERC currently is not developing any additional regional Reliability Standards because the continent-wide NERC Reliability Standards are presently adequate for the SERC region.

6. Southwest Power Pool Regional Entity

SPP RE has a RSDP in place and included in Exhibit C to its RDA. During the assessment period, SPP RE developed a substantially revised RSDP. A principal objective of the revisions was to confirm the SPP RE RSDP more closely to the NERC *Standard Processes Manual*. The revised SPP RE was approved by NERC and filed with the Commission for approval in December 2013, and was approved by the Commission in an order issued January 31, 2014.[11]

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[9] *Planning Resource Adequacy Assessment Reliability Standard*, *Final Rule*, Order No. 747, 134 FERC ¶ 61,212 (2011).

[10] *Regional Reliability Standard PRC-006-SERC-01—Automatic Underfrequency Load Shedding Requirements*, 141 FERC ¶ 61,243 (2012).

[11] *Revised Southwest Power Pool Regional Entity Standards Development Process Manual*, Docket No. RR14-1-000 (January 31, 2014) (unpublished letter order).

SPP RE is not actively developing any Reliability Standards at this time. SPP RE supports development of continent-wide Reliability Standards at NERC. Any regional Reliability Standard developed by SPP RE will go beyond, add detail to, or cover matters not addressed in the NERC Reliability Standards.

During the assessment period, SPP RE developed proposed regional Reliability Standard PRC-006-SPP-1, Automatic Underfrequency Load Shedding Requirements. On November 7, 2012, the NERC Board of Trustees (NERC Board) approved the proposed standard. The purpose of the proposed standard was to ensure the development and implementation of an effective automatic UFLS program for entities in the SPP RE region in order to preserve the security and integrity of the BPS during declining system frequency events. The regional Reliability Standard was designed to develop, coordinate and document requirements for automatic UFLS programs to arrest declining frequency and assist recovery of frequency following underfrequency events in the SPP RE region. On April 26, 2013, NERC submitted the proposed standard to the Commission for approval,[12] but on December 11, 2013, NERC submitted a Notice of Withdrawal of the petition because, due to the creation and pending approval of NERC Reliability Standard PRC-024-1, changes to PRC-006-SPP-01 could be needed to account for generator trip zones that may differ between proposed regional Reliability Standard PRC-006-SPP-01 and NERC Reliability Standard PRC-024-1.[13]

7. Texas Reliability Entity, Inc.

Texas RE has a RSDP in effect and included in Exhibit C to its RDA, and has used its RSDP to develop Texas RE regional Reliability Standards. Texas RE has developed one major regional Reliability Standard, BAL-001-TRE-1, Primary Frequency Response in the ERCOT Region, and two minor regional standards (CIP-001-2a regional variance and IRO-006-TRE-1). The major regional Reliability Standard, BAL-001-TRE, was designed to maintain Interconnection steady-state frequency within defined limits in the ERCOT region; its purpose is to provide a regional Reliability Standard for the ERCOT Interconnection related to the maintenance of steady-state frequency within defined limits by balancing real power demand and supply in real-time. This proposed standard was developed to establish and maintain adequate frequency response in the ERCOT region by ensuring prompt and sufficient frequency response from resources to stabilize frequency during changes in the system generation-demand balance. Because there are physical differences present in the ERCOT system, a more stringent means of assuring frequency response performance was needed than that provided by the continent-wide NERC Reliability Standard. The Commission unconditionally approved the proposed standard by letter order on January 16, 2014 as well as the staggered implementation date requested by NERC

[12] Available at: http://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/FINAL_Petition%20PRC-006-SPP-01_complete.pdf.

[13] *Notice of Withdrawal of the Joint Petition for Approval of Proposed Regional Reliability Standard PRC-006-SPP-01 (Underfrequency Load Shedding*), Docket No. RD13-9-000 (December 11, 2013), available at: http://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/Final_Notice_of_Withdrawal_of_PRC-006-SPP-01_20131211.pdf.

and Texas RE.[14] (The Commission concurrently approved NERC Reliability Standard BAL-003-1, which addresses frequency response on a continent-wide basis.)

8. Western Electricity Coordinating Council

WECC uses the Commission-approved WECC RSDP to develop regional Reliability Standards along with Regional Criteria and Regional Business Practices. WECC develops Regional Criteria and Regional Business Practices to improve the functioning and efficiency of the Western Interconnection. This combination provides a forum for addressing system-wide issues and enables effective oversight to promote reliable operation of the Western Interconnection.[15]

As of the end of the assessment period, WECC had the following eight Commission-approved WECC regional Reliability Standards in effect.

- **FAC-501-WECC-1 (Transmission Maintenance)**

FAC-501-WECC-1 requires, for specified transmission paths, a highly detailed maintenance and inspection plan for all transmission and substation equipment components. This ensures that certain transmission owners of transmission paths identified by a table titled "Major WECC Transfer Paths in the Bulk Electric System" (including associated facilities) have a transmission maintenance and inspection plan (TMIP); and perform and document maintenance and inspection activities in accordance with the TMIP.[16]

- **VAR-002-WECC-1 (Automatic Voltage Regulators)**

NERC continent-wide Reliability Standard VAR-002-1a requires that generator operators operate a generator connected to the interconnected transmission system in automatic voltage control mode unless the operator has notified the transmission operator. WECC regional Reliability Standard VAR-002-WECC-1 adds an additional responsibility for compliance in the WECC region, requiring all synchronous generators within the WECC region to have their voltage regulators in service at all times, with exceptions only for specified circumstances.[17]

- **VAR-501-WECC-1 (Power System Stabilizer)**

NERC continent-wide standard VAR-002-1a requires that a generator operator notify its transmission operator when it removes power system stabilizers (PSS) from service, but does not limit the amount of time for operating generators without PSS in service. WECC regional

[14] *North American Electric Reliability Corporation*, Docket No. RD13-12-000 (January 16, 2014) (unpublished letter order).

[15] While WECC currently maintains Regional Business Practices, all of these fit within the description of Regional Criteria contained in the NERC ROP §313 (Other Regional Criteria, Guides, Procedures, Agreements, etc.). WECC is currently undertaking efforts to re-categorize its Regional Business Practices as Regional Criteria so that going forward WECC will no longer create or maintain items called Regional Business Practices.

[16] *Version One Regional Reliability Standards for Facilities Design, Connections, and Maintenance; Protection and Control; and Voltage and Reactive*, Order No. 751, 135 FERC ¶ 61,061 (2011).

[17] *Id.*

Reliability Standard VAR-501-WECC-1 is more stringent than the NERC Reliability Standard; it ensures that synchronous generators shall be kept in service in order to ensure that the generator provides the proper damping to maintain system stability when generation and transmission outages occur, and an exception is provided only for very specific conditions and for a cumulative time limit per quarter.[18]

- **PRC-004-WECC-1 (Protection System and Remedial Action Scheme Misoperation)**

WECC regional Reliability Standard PRC-004-WECC-1 sets a specific timeframe for the analysis and mitigation of all transmission and generation protection system and remedial action scheme misoperations on major WECC Transfer Paths. This standard augments requirements for certain entities found under NERC continent-wide Reliability Standards PRC-003-1 and PRC-004-1.[19]

- **IRO-006-WECC-2 (Qualified Transfer Path Unscheduled Flow Relief)**

The purpose of WECC regional Reliability Standard IRO-006-WECC-2 is to provide a regional standard that specifies the mitigation of transmission overloads due to unscheduled flow on qualified transfer paths. The standard modifies IRO-006-WECC-1 to correct references, wording, and format issues that would update the standard and bring it into compliance with NERC's drafting conventions for Reliability Standards. On December 20, 2013, NERC and WECC submitted a joint petition to the Commission seeking approval of IRO-006-WECC-2 along with an associated implementation plan and new or revised definitions in the NERC Glossary. On May 13, 2014, FERC issued a letter order approving IRO-006-WECC-2.[20]

- **BAL-004-WECC-02 (Automatic Time Error Correction)**

During the assessment period, WECC revised its regional Reliability Standard BAL-004-WECC-01, Automatic Time Error Correction, resulting in BAL-004-WECC-02. The revision was developed in response to a directive from the Commission in Order No. 723 to modify regional Reliability Standard BAL-004-WECC-01 to clarify certain terms used therein.[21] The purpose of the revised regional Reliability Standard is to maintain Interconnection frequency and to ensure that time error corrections and primary inadvertent interchange playback are effectively conducted in a manner that does not adversely affect the reliability of the Interconnection. On August 20, 2013, NERC and WECC submitted a joint petition to the Commission seeking approval of BAL-004-WECC-02 along with an associated implementation plan, new definitions in the NERC Glossary, and a regional variance to BAL-001-1.[22] The Commission unconditionally approved

[18] *Id.*

[19] *Id.*

[20] *North American Electric Reliability Corporation*, Docket No. RD14-9-000 (May 13, 2014) (unpublished letter order).

[21] *Western Electricity Coordinating Council Regional Reliability Standard Regarding Automatic Time Error Correction*, Order No.723, 127 FERC ¶ 61,176 (2009).

[22] Available at: http://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/Petition%20for%20BAL-004-WECC-02%20and%20BAL-001-1.pdf.

the revised WECC regional Reliability Standard on October 16, 2013, and it became effective as of the date of the order.[23]

- **TOP-007-WECC-1 (System Operating Limits)**

The primary purpose of WECC regional Reliability Standard TOP-007-WECC-1 is to implement the directives in Order No. 693 approving NERC Reliability Standard TOP-007-0, and related concerns, by ensuring that actual flows and associated scheduled flows on major WECC transfer paths do not exceed system operating limits for more than 30 minutes. The Commission approved TOP-007-WECC-1 in an order issued April 21, 2014.[24] In approving TOP-007-WECC-1, the Commission ordered WECC to address the concern regarding the need for WECC to develop a means to provide consistency and transparency when making revisions to the list of major transmission paths instead of the WECC transfer path table and to modify the associated VRFs and VSLs to adequately reflect the size and scope of the actual violation. Any future modifications will be handled through the established standards process.

- **BAL-002-WECC-2 (Contingence Reserve)**

On March 25, 2009, NERC submitted to the Commission for approval WECC regional Reliability Standard BAL-002-WECC-1, Contingency Reserves, but in 2010, the Commission issued Order No. 740 wherein it remanded this standard based on concerns that WECC had not provided adequate technical support to demonstrate that the requirements of the proposed regional Reliability Standard are sufficient to ensure the reliable operation of the BPS within WECC.[25] The purpose of proposed regional Reliability Standard BAL-002-WECC-2 is to provide a regional Reliability Standard that specifies the quantity and types of contingency reserve required to ensure reliability under normal and abnormal conditions. In response to the Commission's directives in Order No. 740, WECC developed modifications to proposed regional Reliability Standard BAL-002-WECC-1. On April 12, 2013, NERC filed a petition with the Commission to approve regional Reliability Standard BAL-002-WECC-2, Contingency Reserve, and associated VRFs and VSLs. On November 21, 2013, the Commission issued Order No. 789 approving WECC regional Reliability Standard BAL-002-WECC-2, the associated VRFs, VSLs, implementation plan, the effective date proposed by NERC and WECC, and the retirement of BAL-STD-002-0 and two WECC regional definitions from the NERC Glossary. In that order, the Commission directed NERC to submit an informational filing after the first two years of implementation of the regional

[23] *North American Electric Reliability Corporation*, Docket No. RR13-11-000 (October 16, 2013) (unpublished letter order).

[24] *Version One Regional Reliability Standard for Transmission Operations*, 135 FERC ¶ 61,062 (2011).

[25] *Version One Regional Reliability Standard for Resource and Demand Balancing*, Order No. 740, 133 FERC ¶ 61,063 (2010).

Reliability Standard that addresses the adequacy of contingency reserve in the Western Interconnection.[26]

II. COMPLIANCE MONITORING AND ENFORCEMENT

The RDAs set forth the delegated authorities and responsibilities of the Regional Entities with respect to compliance monitoring and enforcement.[27] In Exhibit D to each RDA, each Regional Entity adopts the uniform NERC Compliance Monitoring and Enforcement Program (CMEP; Appendix 4C to the NERC ROP) in its entirety, adopts the uniform NERC CMEP with stated differences, or adopts a separate CMEP (however, the CMEP of a Regional Entity that has deviations from or is different than the uniform CMEP must comply with the requirements of the RDA and with §403 of the NERC ROP).

The RDA gives the Regional Entities delegated authorities and responsibilities to, among other things, maintain a program of proactive monitoring and enforcement of compliance with Reliability Standards in accordance with the CMEP and the annual NERC CMEP Implementation Plan (IP);[28] report to NERC any possible violations, alleged violations or confirmed violations of Reliability Standards and the dispositions thereof; maintain violations as nonpublic until the matter is filed with the Commission as a Notice of Penalty (NOP); conduct, in a confidential manner, compliance investigations of possible violations and alleged violations; and maintain a conflict of interest policy to ensure the integrity and independence of the Regional Entity's CMEP, including the integrity and independence of the persons or decision-making bodies making final determinations in compliance enforcement actions.

In addition, the RDAs give the Regional Entities responsibilities with respect to the registration of owners, operators and users of the BPS as entities responsible to comply with mandatory Reliability Standards; and with respect to the certification of certain registered entities to perform certain reliability functions.[29]

Section 4 of the RDAs obligates the Regional Entity to comply with, among other things the NERC ROP. Provisions of the ROP applicable to compliance monitoring and enforcement functions, include, in addition to the uniform CMEP, the following ROP sections and appendices: §400, Compliance Enforcement (§403 sets forth required attributes of Regional Entity CMEPs), §500, Organization Registration and Certification, Appendix 4B, *Sanction Guidelines*, Appendix 5A, *Organization Registration and Certification Manual*, Appendix 5B, *Statement of Compliance Registry Criteria*, and Appendix 5C, *Procedure for Requesting and Receiving an Exception from the Application of the NERC Definition of Bulk Electric System* (effective July 1, 2014).

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[26] *Regional Reliability Standard BAL-002-WECC-2 – Contingency Reserve*, Order No. 789, 145 FERC ¶ 61,141 (2013).

[27] Generally, each Regional Entity's responsibilities with respect to compliance monitoring and enforcement are set forth in §6 of its RDA.

[28] Available at: http://www.nerc.com/pa/comp/Resources/Pages/default.aspx.

[29] These provisions are generally found in §7 of the RDAs.

In this §II, NERC describes and evaluates the Regional Entities' performance during the assessment period separately with respect to the three major components of their compliance monitoring and enforcement responsibilities: Organization Registration and Certification (ORC) (§II.A below), Compliance Monitoring (§II.B below), and Compliance Enforcement (§II.D below). In addition, Compliance Investigations are discussed separately in §II.C.

A. Organization Registration and Certification

NERC is ultimately responsible for devising the criteria that determine which BPS users, owners and operators are subject to approved Reliability Standards, and for maintaining the NERC Compliance Registry of organizations subject to Reliability Standards. In carrying out these responsibilities, NERC relies on the Regional Entities to apply and implement registration and certification criteria as part of the ORC program. Pursuant to the RDAs and §500 and Appendices 5A (*Organization Registration and Certification Manual*) and 5B (*Statement of Compliance Registry Criteria*) of the NERC ROP, the Regional Entities are responsible for the following registration and certification tasks:

Registration

(1) Providing NERC with timely and accurate information relating to registrations and registered entities to enable NERC to maintain a registration database that is accurate and up-to-date;

(2) Collecting data on and mapping BPS facilities and those facilities that have a material impact on the BPS within each Regional Entity's defined regional boundaries;[30]

(3) Approving or disapproving entity registration applications;

(4) Notifying NERC of each coordinated functional registration (CFR) and joint registration organization (JRO) that the Regional Entity accepts; and

(5) Maintaining a list of active CFRs and JROs.

Certification

(1) Verifying that all reliability coordinators, balancing authorities, and transmission operators (i.e., the reliability entities required to be certified to perform their reliability functions) meet the registration requirements of ROP §501.1.4;

(2) Reviewing entity certification applications for completeness and notifying NERC of applications;

[30] Each Regional Entity's boundaries are defined in Exhibit A to its RDA.

(3) Evaluating the competency of entities requiring certification to meet the NERC certification requirements;

(4) Establishing certification procedures, including (i) evaluation processes, schedules, and deadlines; (ii) expectations of the applicants and all entities participating in the process; and (iii) requirements for certification team members;

(5) Approving or denying certification team recommendations and notifying the entity and NERC of the decision; and

(6) Providing leadership to the certification team throughout the certification process.

NERC and the Regional Entities are working towards two goals for registration. First, they recognize the need for consistency between and among Regional Entities and across the continent in the application of the criteria for registering entities. Second, any entity whose facilities or operations are reasonably deemed material to the reliability of the BPS will be registered, irrespective of other considerations.

During the assessment period, the NERC ORC program increased its efforts regarding consistency and transparency. The ORC program developed and posted on NERC's website eight registration and 38 certification templates to be used by the Regional Entities and industry. The ORC program worked with the Certification and Registration Working Group to develop a prototype common registration form (CRF). The CRF requires the provision of information related to entity relationships, and will thereby provide greater assurance that all entities that should be registered are in fact registered. Further, since consistent forms are now used by each Regional Entity, entities that need to register in multiple Regional Entities should find the registration process more streamlined.

During the assessment period, the ERO experienced an incremental increase in the number of registered entities. As of January 30, 2009, NERC and the Regional Entities had registered a total of 1,860 entities for a total of 4,482 reliability functions. As of May 1, 2014, NERC and the Regional Entities have registered 1,920 entities for 4,774 reliability functions. Further, a review of the registration activity by Regional Entity shows a significant number of registrations and deactivations in four Regional Entities (NPCC, ReliabilityFirst, Texas RE, and WECC) for the following three functions: (i) generator owners; (ii) generator operators; and (iii) purchasing-selling entities. This trend is in part attributed to corporate ownership changes. The registration and deactivation activity in the remaining Regional Entities (FRCC, MRO, SERC, and SPP RE) was minimal.

The JRO and CFR mechanisms are important components of the ORC program. These vehicles are used to define the responsibilities and accountability among entities separately registered for the same function. During the assessment period, revisions to NERC ROP §507 and the addition of §508, approved by the Commission on June 10, 2010, clarified the operations of

both types of registration.[31] Specifically, revised ROP §507 allows an entity to register as a JRO on behalf of one or more of its members or related entities for one or more functions for which such members or related entities would otherwise be required to register. The registering entity thereby accepts on behalf of such members or related entities all compliance responsibility for that function or those functions including all reporting requirements. NERC ROP §508 allows multiple entities to register using a CFR for one or more Reliability Standard(s) or for one or more requirements or sub-requirements with particular Reliability Standard(s) applicable to a specific function. The CFR is the complete registration for each entity, with each entity taking full compliance responsibility for those Reliability Standards or requirements or sub-requirements applicable to the CFR.

Many of the registered entities that use the NERC ROP §507 process are cooperatives, municipalities, and other publicly-owned or member-owned utilities. As of May 1, 2014, a total of 34 JROs are registered; however, NPCC, SPP RE, and WECC have not registered any JROs.[32] Since its initial implementation, use of the joint registration option has been fairly static, with few additional entities registering as JROs or changing their JRO status. Many registered entities have, however, taken advantage of the opportunity to coordinate their registered functions pursuant to NERC ROP §508. There are a total of 44 CFR agreements, with FRCC being the only Regional Entity in which there is not a coordinated registration. Some of these coordinated registration agreements cross Regional Entity boundaries.

As the above discussion indicates, the registration and certification processes have been fairly stable during the assessment period in terms of the numbers of entities registered and certified. However, NERC has identified several initiatives or opportunities for improvement in how the Regional Entities perform their registration and certification functions. The first initiative is in the area of multi-regional registered entities (MRREs). MRREs are entities that own or operate BES facilities in two or more Regional Entity footprints. MRREs pose a consistency challenge because they are subject to multiple compliance programs. To address this challenge, during the assessment period, several Regional Entities partnered to coordinate their compliance and enforcement efforts with respect to MRREs. In particular, they developed a "lead region" model in which the involved Regional Entities select one of them to lead the compliance and enforcement efforts for a given MRRE. The purpose of this MRRE initiative is to describe the coordinated CMEP processes that will be used by NERC and the Regional Entities for a subset of registered entities that are registered in multiple Regional Entities and volunteer for this program. The MRRE process provides the opportunity for these entities to request to be accountable to one Compliance Enforcement Authority (CEA). The coordinated MRRE process provides for increased efficiencies in compliance resource allocation for NERC, the Regional Entities, and the registered entities while, maintaining the reliability of the BPS.

[31] *North American Electric Reliability Corporation*, Docket No. RR10-8-000 (June 10, 2010) (unpublished delegated letter order).

[32] *See* the JRO member listing Excel spreadsheet available at: http://www.nerc.com/pa/comp/Pages/Registration-and-Certification.aspx.

A second area of opportunity for improvement is the efficiency with which a Regional Entity is able to process registration activation and deactivation requests. This initiative is part of the risk-based registration effort described in further detail in the *Overview of NERC Activities and Accomplishments in the Five-Year Period*.

B. Compliance Monitoring

1. NERC Oversight of Regional Entity Compliance Monitoring Activities

NERC's oversight of and involvement with the Regional Entities' compliance monitoring activities is ongoing and continuous. Although this document is a five-year assessment of the Regional Entities' performance of specified functions, including compliance monitoring, NERC's ongoing oversight of and involvement with the Regional Entities' compliance monitoring activities provides a significant component of the informational and observational basis for NERC's evaluation of the Regional Entities in this area. This §II.B.1 provides an overview of NERC's oversight activities for the Regional Entity compliance monitoring programs, which is one of the key information and observation sources for NERC's assessment of the Regional Entities' performance.

At the start of the assessment period, the Regional Entity audit program consisted of Agreed-Upon Procedures (AUP) developed by NERC in collaboration with an independent third-party. The AUP oversight program operated on a three-year audit cycle.

In 2010, NERC restructured its Regional Entity oversight program. Based on NERC's observations of the audits completed under the AUP oversight program, NERC determined that conducting an AUP audit once every three years did not provide the desired level of qualitative evaluation of effectiveness of the programs within and across the Regional Entities. As a result, NERC refocused the Regional Entity audit program to move to an on-going and simultaneous evaluation of performance-based objectives to gauge the effectiveness of the Regional Entities' CMEPs. NERC staff utilized the findings, exceptions and lessons learned from the initial AUP program engagements to develop processes and procedures for the restructured audit program. The restructured Regional Entity oversight program provides for continuous oversight of each Regional Entity in focused, discrete time intervals that allows NERC to provide immediate feedback to Regional Entity compliance staff. This feedback enables Regional Entity staff to improve the consistency of its compliance processes and their application in a timelier manner.

Under NERC's current oversight model, NERC Audit Assurance and Oversight (AAO) staff and the Regional Entities conduct compliance monitoring of registered entities primarily through regular and scheduled compliance audits and random spot checks. Each Regional Entity has a compliance monitoring program that includes all the compliance monitoring methods specified in the uniform NERC CMEP, Appendix 4C to the NERC ROP.[33] NERC is responsible

[33] The compliance monitoring methods are compliance audits, self-certification, spot checks, investigations, self-reports, periodic data submittals, and complaints. *See* CMEP §3.0 (Compliance Monitoring Processes). The Regional Entities review self-certifications for all registered entities at least once annually. Some Regional Entities also require monthly self-certifications for certain Reliability Standards and requirements. Periodic data submittals occur on an ongoing basis, with certain information due to the Region Entity on a monthly basis, and other data due on a quarterly basis.

for oversight and monitoring of the Regional Entities' compliance monitoring activities, which must be carried out in accordance with the NERC ROP and the terms of the RDAs. NERC uses the following tools (each of which is described in the subsections below), to carry out its oversight and monitoring of the Regional Entities' activities:

(1) An annual review of Regional Entity CMEP IPs for approval and posting, as well as an annual review of each Regional Entity's CMEP for incorporation into the ERO's annual CMEP report;

(2) Annual assessments of compliance monitoring for selected Reliability Standards for consistency of approach through the Key Reliability Standard Spot Check (KRSSC) program;

(3) Oversight audits of selected registered entity compliance audits performed by Regional Entities, as well as periodic assessments of Regional Entity auditor capabilities;[34] and

(4) NERC training for Regional Entity CMEP personnel.

The oversight engagement of NERC AAO staff and Critical Infrastructure department (CID) staff, as well as NERC Training and Education program staff, increased over the assessment period, thereby providing an enhanced view of the Regional Entities' performance. These oversight activities are further discussed below.

a. Annual CMEP Implementation Plan

As part of NERC's annual oversight, each Regional Entity is required to develop and submit to NERC, for approval, an annual Regional Entity CMEP IP in accordance with Appendix 4C of the ROP. In its IP, each Regional Entity identifies which Reliability Standards and requirements it will actively monitor, evaluate, report, sanction and appeal during the period covered by the IP (both those Reliability Standards and requirements that NERC specifies shall be monitored, and any additional Reliability Standards and requirements the Regional Entity proposes to monitor). These IPs are submitted to NERC on the schedule established by NERC, generally on or about October 1 of the preceding year. NERC previously published the Regional Entity IPs, and its own IP, as separate documents; however, beginning with the 2014 IPs, NERC now combines its IP and the Regional Entity IPs into a single document.[35]

Each Regional Entity must also report annually to NERC regarding how the Regional Entity carried out its delegated compliance monitoring and enforcement authority in the previous year, the effectiveness of its CMEP, and changes it expects to make to correct any deficiencies

[34] Due to ongoing restructuring and transitioning pursuant to the Reliability Assurance Initiative (RAI), these compliance activities ceased in early 2013, but are scheduled to resume in the fourth quarter of 2014.

[35] *See ERO Compliance Monitoring and Enforcement Program 2014 ERO CMEP Implementation Plan*, version 1.1, available at: http://www.nerc.com/pa/comp/Resources/ResourcesDL/2014_ERO_CMEP_IP_v1.1_%2804012014%20posting%29.pdf.

identified. Each Regional Entity provides its annual report on a schedule established by NERC, generally on or about February 15 of the following year. The Regional Entities' annual reports, along with Regional Entity responses to an annual NERC CMEP survey, are used to prepare NERC's annual CMEP report.

b. Key Reliability Standard Spot Check Program

The KRSSC program focuses on issues that have the highest potential to result in major impacts to the BPS. Through the KRSSC program, NERC compares and contrasts the procedures Regional Entities use when auditing a set of high-risk, high-impact or frequently violated Reliability Standards. The KRSSC focuses on the observation activities of the Regional Entity compliance audit team during pre-audit work and on-site audit work, as these are the primary audit observation procedures used in gathering and analyzing evidence. Through this program, NERC seeks to identify issues that Regional Entity audit teams experience when evaluating compliance with selected Reliability Standards, as well as areas in Regional Entity audit evaluations for which additional guidance may be needed to improve evaluation processes or to promote consistency in evaluations. The objective of the KRSSC program is not to identify a minimum acceptable auditing approach or to determine the best practices for determining compliance; rather, the emphasis is upon enhancing consistency and improving auditing approaches. The KRSSC process addresses a need, which was identified early in the assessment period, to increase opportunities to share best practices among Regional Entities.

For issues identified during KRSSCs, NERC provides Regional Entities with overall recommendations and guidance as needed regarding how to remediate issues and to enhance consistency across all the Regional Entities. Regional Entities also receive individualized information through confidential appendices. NERC audit staff holds teleconferences with each Regional Entity to discuss both Regional Entity-specific results and cross-Regional Entity results. NERC's proposed best practices are intended to apply to enhance elements of the Regional Entities' auditing practices and approaches. While NERC typically derives the KRSSC recommendations and best practices from review of the auditing practices for specific Reliability Standards, many of the audit practices and approaches identified have broader applicability to other Reliability Standards.

During the assessment period, NERC conducted three KRSSCs with the Regional Entities. The three KRSSCs focused on the following Reliability Standards: EOP-005-1, PRC-005-1, CIP-001, and EOP-004 (the latter two were evaluated jointly). For each KRSSC, two registered entity compliance audits from each Regional Entity were selected based upon the potential and actual risk posed to the BPS by the audited registered entities as well as the completion date of the audits. As part of its evaluation, NERC AAO staff examined the credentials, resource levels and audit implementation methods of the individual Regional Entities in conducting their compliance audits. NERC evaluated the Regional Entities separately during this process; however, in an effort to increase consistency, NERC communicated any departure from best practices to the individual Regional Entities.

c. Oversight Audits of Regional Entity Audits of Registered Entities

NERC conducts oversight audits of selected registered entity audits being performed by Regional Entities. The purpose of an oversight audit is to determine whether the Regional Entity conducted its compliance audit and related tasks in accordance with the requirements of the NERC ROP, the CMEP and the RDAs. NERC staff members observe a Regional Entity compliance audit of a registered entity on-site at the registered entity or at the relevant Regional Entity's office. A Regional Entity audit of Operations and Planning Reliability Standards is observed by NERC AAO staff, while a Regional Entity audit of Critical Infrastructure Protection (CIP) Reliability Standards is observed by NERC CID staff. The Commission may also assign auditors to participate by observing the pre-audit activities and the on-site audit, although Commission participation is not specifically a component of the NERC oversight audit. Following the oversight audit, NERC AAO staff identifies best practices and recommendations for the Regional Entity.

d. NERC Training Activities for Regional Entity Compliance Staff

Early in the assessment period, NERC and the Regional Entities identified training, education and communication as key initiatives for compliance monitoring. As a result, during the assessment period, training opportunities for Regional Entity CMEP staff (as well as for registered entities) have been increased.[36]

Training of CEA staff is a central component of NERC's compliance monitoring oversight of Regional Entities. NERC's training programs for compliance auditors are based upon the U.S. Government Accountability Office's Generally Accepted Government Auditing Standards (GAGAS) for performance audits. GAGAS is primarily used by auditors of government entities and entities that receive government grants and other funding. All of NERC's CEA training material is reviewed and updated based on changes to GAGAS, the CMEP, the NERC ROP, and internal procedures, as well as feedback from experience.

From 2009 to 2013, NERC conducted the following training sessions for ERO compliance auditors:

- 18 auditor workshops and webinars
- 11 audit team leader (ATL) training sessions
- 3 CIP training sessions
- 12 compliance investigation training sessions

In addition, NERC made a total of 25 presentations at Regional Entity compliance workshops, including 18 presentations in 2012. Examples of topics presented in the auditor workshops and webinars during this period included:

- Fundamentals of NERC Compliance Audits
- GAO Auditing Standards
- Audit Scoping

[36] Regional Entity training activities provided for registered entities are described in §II.B.2.a below and in the individual Regional Entity assessments in §II.B.2.b below.

- Auditor Checklist and Handbook
- Gathering Quality Evidence
- Sampling/Random Sampling Techniques
- Quality Audit Documentation
- Conducting Performance Audits
- Find, Fix, Track, and Report (FFT) Process
- Internal Controls
- CIP Reliability Standards
- Critical Asset Identification and CIP-002 Sufficiency Reviews
- CIP Compliance

2. NERC Evaluation of Regional Entity Compliance Monitoring Programs

Subsection 2.a below discusses, on a collective basis, the Regional Entities' training and education programs for registered entity personnel. Each Regional Entity maintains, for organizational, budgeting and accounting purposes, a Training, Education, and Operator Certification program separate from its Compliance Monitoring and Enforcement and Organization Registration and Certification program. For purposes of this assessment, the Regional Entities' training, education and outreach activities are being discussed and assessed as part of the evaluation of their compliance programs because these activities are heavily focused on compliance-related topics. Subsection 2.b then evaluates each Regional Entity's compliance monitoring program on an individual basis.

a. Regional Entity Training, Education, and Outreach Programs for Registered Entity Personnel

The RDAs provide that the Regional Entity "may provide training and education to registered entities, as it deems necessary, in support of its performance of delegated functions and related activities under this Agreement."[37] Providing training for registered entities is critical to reliability for the following reasons:

(1) To ensure that registered entities understand what is required to comply with Reliability Standards, with a particular focus on the most frequently violated Reliability Standards;

(2) To equip registered entities with the tools to identify risks to reliability; and

(3) To help registered entities establish compliance programs that systematically detect, report, correct and prevent risks to reliability and therefore reduce violations.

The Regional Entities offer two types of training opportunities for registered entities. First, each Regional Entity conducts training and outreach initiatives with registered entities through its

[37] This provision is generally found in §7(e) of the RDAs.

Training, Education, and Operator Certification program. Under this program, Regional Entities offer NERC-approved continuing education program courses and activities necessary to maintain one's status as a NERC-certified system operator. The target audience of the program is BPS operating personnel, including system operations personnel, operations support personnel (engineering and information technology), supervisors and managers, and training personnel. NERC's Personnel Certification and Continuing Education staff and Training and Education staff support the Regional Entities' efforts in this area. Second, Regional Entities conduct supplemental compliance and enforcement training for registered entities, typically through workshop events. For the supplemental compliance and enforcement training and outreach for registered entities, the Regional Entity has the discretion to choose the content, delivery method, and location of such training.

Feedback from registered entities regarding the Regional Entity training workshops has been very positive, and participants have sought coverage of additional topics. To address requests from the industry for an increased level of compliance information as well as for enhanced CMEP transparency, many Regional Entities have committed more resources to training in order to engage in additional training, education and outreach activities. These increased activities have included additional workshops, newsletters to industry, and other direct communications. Much of the information covered by these increased outreach and communication activities takes the form of lessons learned.

b. Assessments of the Individual Regional Entities

As an overall evaluation, during the assessment period, the Regional Entities made meaningful progress in improving their compliance monitoring programs and their audit practices and procedures consistent with the requirements of the ROP (specifically, the CMEP, Appendix 4C) and the RDAs. Overall, the Regional Entities worked diligently to plan and complete their scheduled compliance audits during the assessment period. NERC's oversight of the Regional Entity compliance programs shows that the Regional Entities are meeting the baseline requirements of the ROP and the RDAs. NERC's oversight has also shown that there continue to be varying compliance monitoring practices across the ERO.

NERC has three main objectives for the continued evolution of the compliance monitoring program. First, the Regional Entities are revising their existing practices to better align with risk using generally accepted audit practices. Second, NERC and the Regional Entities have developed a standardized audit checklist to ensure consistent conduct of audits across the ERO. Third, NERC, in conjunction with the Regional Entities, has developed competency guidelines for compliance monitoring staff and is developing training to accompany the competency guidelines. Through RAI, the ERO Enterprise is moving away from a one-size-fits-all approach for monitoring registered entities to a compliance oversight approach that considers risk and the controls registered entities have established around compliance with Reliability Standards.

NERC AAO staff has collaborated with the Regional Entities to develop RAI pilot projects conducted by several Regional Entities. Some Regional Entities volunteered to establish pilot programs to test strategies regarding: (i) entity risk assessment; (ii) management controls (identification and testing methodology); (iii) audit scope linked to risk; and (iv) data gathering techniques (interviews, surveys, etc.) and the process for disseminating the pilot across the ERO.

The participating Regional Entities then conducted the pilot programs with registered entities within their respective footprints. Each participating Regional Entity used varying techniques with the goal of establishing a repeatable risk assessment and internal control review process, tied to Reliability Standards that could be replicated by non-participating Regional Entities.

In the individual Regional Entity assessments that follow, NERC examines how the Regional Entities satisfied the baseline requirements of the ROP and RDAs in executing their compliance monitoring responsibilities during the assessment period. NERC's review encompassed two major areas: (i) department structure and staffing, and (ii) compliance monitoring tools and audit planning. With respect to the first area, NERC examined the structure of the Regional Entity CMEP departments, the adequacy and qualifications of staff resources, and the involvement of industry SMEs and Regional Entity members, as well as the existence of policies to maintain the independence and integrity of the Regional Entity compliance staff. In the second area, NERC examined the compliance monitoring tools available to assist the Regional Entities in audit planning and execution. Elements central to these audit planning and execution efforts are validation of data accuracy, confidentiality of audit information, and quality assurance of audit findings and audit reports. In addition, for each Regional Entity compliance monitoring program, NERC reviewed the Regional Entity's guidance and training offered to industry stakeholders and its participation to date in RAI.

i. Data on Regional Entity Compliance Resources

The following two tables show the amounts of (i) budgeted direct expenses and (ii) budgeted direct full-time equivalent (FTE) staffing in each Regional Entity's CMEP in 2009 and 2014, as taken from their business plans and budgets filed with the Commission. These figures are for the Regional Entity's entire Compliance Monitoring and Enforcement and Organization Registration and Certification program.[38] As the tables show, during the assessment period, each Regional Entity significantly increased its budgeted direct expenses and its budgeted FTE staffing for its CMEP.

Regional Entity	2009 Budget	2014 Budget	Percent Increase
FRCC	$2,019,650	$4,281,909	112.0%
MRO	$2,071,510	$3,864,192	86.5%
NPCC	$2,095,204	$5,080,485	142.5%
RFC	$5,099,328	$9,788,246	92.0%
SERC	$4,805,617	$7,389,556	53.8%
SPP RE	$1,283,653	$4,258,217	231.7%
Texas RE	$1,628,935	$5,991,654	267.8%
WECC	$6,165,303	$8,592,053	39.4%

Regional Entity	2009 FTE	2014 FTE	Percent Increase
FRCC	9.26	19.26	108.0%
MRO	10.00	21.26	112.6%

[38] MRO's 2014 budgeted expense does not include the expenses for its Organization Registration and Certification activities, which MRO conducted in and budgeted under its Reliability Standards program.

NPCC	9.00	16.00	77.8%
RFC	23.00	43.00	87.0%
SERC	21.50	42.50	97.7%
SPP RE	6.00	22.10	268.3%
Texas RE	14.15	40.00	182.7%
WECC	30.00	58.00	93.3%

ii. Florida Reliability Coordinating Council, Inc.

Department Structure / Staffing / Conflict of Interest Avoidance

During the assessment period, FRCC's Compliance department was split into two sections, a Compliance Monitoring group and an Enforcement group. In October 2012, FRCC separated the reporting of these two groups to create more independence between monitoring and enforcement activities. The manager of compliance enforcement reports directly to the vice president and executive director of reliability standards and compliance while the manager of compliance audits reports to the director of compliance. In addition, in June 2014, FRCC created a third group, Risk Assessment and Mitigation. This group is focused on risk assessment, both before a compliance monitoring activity takes place, to help determine the scope of the monitoring oversight; and after a possible violation is discovered, to help to determine the risk posed by the violation so that the most efficient disposition can take place. The risk evaluation before a compliance monitoring activity takes place will include both inherent risk assessment and assessment of the registered entity's internal controls. Additionally, the Risk Assessment and Mitigation group is now the primary contact for registered entities with respect to the development, implementation and completion of mitigation plans. The manager of risk assessment and mitigation reports to the director of compliance.

While NERC does not specifically endorse a particular organizational structure for CMEP departments at the Regional Entity level, NERC supports department models that facilitate the prioritization of risk. All Regional Entities are currently evaluating the structure of their CMEP departments to similarly assess how best to organize around risk.

With the recent change just described, FRCC's Compliance Monitoring group consists of eight positions, while the Risk Assessment and Mitigation group consists of four positions. Many of FRCC's audit team members individually have over 15 years of industry experience. Five audit team members were certified or hold active NERC certifications as system operators. Between 2011 and 2012, FRCC increased its staffing to add areas of expertise.

FRCC CIP auditors are required to at least have Certified Information Systems Security Professional (CISSP) certification or Certified Internal Security Auditor (CISA) certification and to demonstrate security background knowledge covering multiple domains including physical and network security. Each CIP auditor is required to maintain this certification by attending annual conferences and training seminars to achieve the required minimum of 20 continuing professional education hours annually. The FRCC manager of compliance audits is responsible for vetting the topics covered during these conferences and seminars.

The FRCC Compliance Monitoring group prepares its Operations and Planning auditors to be supplemental team members during CIP audit engagements by conducting training sessions for them to review NERC CIP Reliability Standards and evidence that can be used to demonstrate compliance with those Reliability Standards. The Operations and Planning auditors serve as supplemental team members for CIP audits on a rotational basis to increase their knowledge of CIP Reliability Standards.

FRCC tracks the on-going educational needs related to certifications for both CIP and Operations and Planning auditors. FRCC also develops an annual budget to support this training effort. During the assessment period, FRCC began using the *Compliance Auditor Capabilities and Competency Guide* recently developed by the ERO Enterprise,[39] as well as building a matrix to plan for and ensure training and development opportunities for the range of skills needed in the auditor positions. The FRCC audit team members participate in various auditor training sessions and workshops. FRCC audit staff members are required to attend NERC-sponsored ERO training.

Although FRCC is not presently using SMEs from outside the organization for its CIP or Operations and Planning audit engagements, FRCC has developed a procedure should it need to use such experts in the future. This procedure is titled *Procedure for the Use of Industry Volunteer Subject Matter Experts* and is posted alongside the *Nomination Form for the Industry Volunteer Subject Matter Expert Pool* on FRCC's website. This procedure guides FRCC compliance staff on the use of industry volunteer SMEs.

FRCC has adopted policies and procedures to avoid conflicts of interest in its CMEP work. During the assessment period, FRCC implemented an Annual Employee Recital and Disclosures process. Each FRCC employee receives a copy of the FRCC *Conflict of Interest Policy* and signs the *Conflict of Interest Questionnaire, Disclosure Statement of Stock Ownership of FRCC Member Companies*, and *Non-Disclosure Acknowledgement*. FRCC maintains a document titled *FRCC Auditor Objectivity, Independence and Impairment* on its public web page. This document provides, among other things, that auditors must remain free from "personal impairments to independence" that might cause auditors to limit the scope of their audit or alter audit findings.

Compliance Monitoring Tools and Procedures

FRCC utilizes a number of tools to execute its audits, several of which are highlighted in this section. FRCC uses an evidence index tool to catalogue evidence submitted throughout the audit process. FRCC references the evidence index numbers when referring to documentation during compliance audits and includes these references in its audit documentation. FRCC also developed its own tool for tracking additional evidence requests and for issuing follow-up data requests. These tools increase the efficiency of its audits by facilitating tracking. In addition to these tools, FRCC audit teams use several other standard auditor tools. For example, FRCC utilizes the RSAWs and the Regional Advanced Techniques Staff (RAT-STATS) sampling tool.

[39] *See ERO Enterprise Compliance Auditor Manual* (Auditor Manual) available at: http://www.nerc.com/pa/comp/Pages/ERO-Enterprise-Compliance-Auditor-Manual.aspx.

In 2012, FRCC developed its own risk assessment document to use as an interim step until NERC and the Regional Entity working groups create a template for ERO-wide use.

FRCC maintains copies of its *Compliance Audit Procedure*, *Spot Check Procedure*, and *Compliance Investigation Procedure* on its public web page. The procedures are reviewed periodically and updated as necessary. FRCC's Compliance Tracking and Submittal system (CTS) is also central to its compliance monitoring efforts. The database provides multiple functionality for entities registered in FRCC including:

(1) The ability to input and maintain registered entity contact information;

(2) The ability to submit and update CIP Technical Feasibility Exceptions (TFEs);

(3) The ability of FRCC Compliance staff to review draft registered entity compliance responses, such as mitigation plans, prior to submittal by the registered entity;

(4) The ability to submit compliance-related documentation; and

(5) The ability to allow the review of historical compliance submittals.

FRCC Compliance staff use a related software system called Compliance Information Tracking System (CITS) to store information related to processing of violations and mitigation plans. CITS is also used for developing reports for management, development of metrics and for supplying data to the NERC associated database.

Quality Assurance

After each compliance audit or spot check, the FRCC team involved conducts a lessons learned session focused on quality and process improvement. Action plans are developed to address these lessons learned. To ensure completeness and consistency, the manager of compliance audits reviews all audit reports before they are finalized and shared with NERC and the registered entity. FRCC Compliance staff have developed a number of internal procedures based upon the procedures and requirements identified in the NERC ROP. These procedures are reviewed on an annual basis and updated as necessary. These procedures are followed to ensure that FRCC Compliance staff implement compliance and enforcement activities in accordance with the guidance established by NERC and FERC.

Guidance and Training for Industry Stakeholders

FRCC utilizes its compliance workshops as the primary mechanism for outreach to its registered entities. In 2013, FRCC hosted two general compliance workshops (with an Operations and Planning focus) and one CIP compliance workshop. During these workshops, multiple techniques are used to increase the effectiveness of addressing current topics including use of registered entities to provide presentations on "best practices." Registered entities are encouraged to discuss compliance-related topics with auditors during small group breakout sessions. FRCC also conducts webinars on various topics of interest to registered entities throughout the year. Previous webinars covered topics such as preparing for an audit, enforcement process, audit approaches for specific Reliability Standards, the transition to Version 5 of the CIP Reliability

Standards, and the annual FRCC CMEP IP. FRCC also maintains a Frequently Asked Questions section on its website. FRCC Compliance staff participates in regular Regional Entity Committee and Compliance Forum (RECCF) meetings to disseminate the latest information regarding its compliance program to industry stakeholders. In addition FRCC CIP auditors are regularly scheduled on the agenda of the regional member services CIP Subcommittee meetings that are held monthly to address CIP monitoring processes and CIP audit approach issues.

Maintaining Confidentiality

There are strict confidentiality requirements associated with all CMEP activities.[40] FRCC follows the NERC CMEP to maintain the confidentiality of any complaint and maintains a link to NERC's complaint reporting page from the FRCC web site. FRCC ensures that its officers, directors, and employees with access to confidential data and information are under obligations of confidentiality pursuant to the *FRCC Confidentiality Policy*. Annually, all FRCC Compliance and Enforcement staff is trained on the *FRCC Confidentiality Policy*. FRCC has also implemented a secure vault system to receive electronic compliance evidence from registered entities. The vault system uses 256-bit advanced encryption standard (AES) cipher encryption to deliver evidence to FRCC. Access to the vault is restricted to Compliance staff and supporting IT staff, and CIP evidence is limited to viewing only in the vault.

Participation in RAI

FRCC Compliance staff have been involved in several aspects of RAI. FRCC provided a participant on the ERO Compliance and Enforcement Management Group (ECEMG) Manual Task Force (MTF) that developed the *Compliance Auditor Handbook* and associated *Compliance Auditor Checklist*, as found in the Auditor Manual. FRCC also provided personnel to aide in the training of auditors relative to the handbook and checklist at the ERO auditors workshop.

In January 2014, FRCC Enforcement staff began to triage and review all possible violations to determine the disposition method within 60 days on average. FRCC is participating in the piloting of an approach that allows selected registered entities to aggregate and submit periodically any possible minimum risk violations they may have for certain Reliability Standards and requirements.

FRCC Compliance staff have been involved with the pilot integration team that is reviewing the results of Regional Entity pilots concerning inherent risk assessment and internal controls evaluation to determine the ERO approach to scoping more risk-based compliance monitoring.

iii. Midwest Reliability Organization

Department Structure / Staffing / Conflict of Interest Avoidance

In 2009, MRO split its CMEP function into three distinct departments, each with its own assigned personnel: (i) Compliance; (ii) Risk Assessment and Mitigation; and (iii) Enforcement.

[40] *See* ROP §402.8 (NERC Oversight of the Regional Entity Compliance Monitoring and Enforcement Programs — Confidentiality).

MRO Compliance staff conduct audits and spot checks of compliance with Reliability Standards by registered entities. Since 2009, MRO has expanded its Compliance staff from five to eight auditors, split evenly between Operations and Planning and CIP, with most of the additions being CIP auditors. MRO seeks to achieve a balance of skills in its Compliance department, including technical expertise and audit experience. This balance is achieved through hiring of staff with needed skillsets and experience (i.e., system planning, protection systems, or cybersecurity) as well as through supplemental training. Training on core skills, such as ethics or audit practices, is offered generally, while specific skill gaps or training needs are identified on an individual basis. MRO currently has Operations and Planning auditors who are all certified as either NERC system operators or registered professional engineers. CIP audit staff generally hold certifications, such as CISSP and CISA that align with Department of Defense requirements.[41]

MRO Risk Assessment and Mitigation staff undertake an independent review of the facts and circumstances surrounding each violation discovered by Compliance staff. They determine whether sufficient evidence supports each possible violation. Risk Assessment and Mitigation staff also work with the registered entity to develop an effective and comprehensive mitigation plan in the event that a violation is confirmed.

Confirmed violations move to the Enforcement department staff, who review recommendations made by Risk Assessment and Mitigation staff, verify all relevant facts, and evaluate appropriate enforcement actions. The factual review conducted by Risk Assessment and Mitigation and Enforcement staff is intended to ensure a consistent, accurate application of the NERC Reliability Standards. Through this segregation of duties, MRO seeks to establish independence among those making the findings, those assessing risk, and those determining and negotiating penalties and sanctions.

MRO has adopted policies and procedures to avoid conflicts of interest in its CMEP work and to ensure the independence of its staff. Those policies and procedures provide that:

(1) No MRO director or member of MRO committees may participate in any way in compliance violation investigations, compliance audits, reports, sanction determinations, or other matters within the CMEP.

(2) An MRO director or member of an MRO committee may engage in actions on behalf of his or her employer regarding a compliance monitoring and enforcement matter undertaken by MRO; however, that director or member of an MRO Committee must recuse himself or herself from any board or committee decisions, meetings, and actions related to that compliance monitoring and enforcement matter. Potential concerns about the participation of a MRO director or member of an MRO committee are brought to the attention of the president and chief executive officer who will seek an appropriate resolution of the matter with the advice and counsel of the independent directors.

[41] *See* Department of Defense Directive 8570.1, "Information Assurance Training, Certification, and Workforce Management" (August 15, 2004) available at: http://www.dtic.mil/whs/directives/corres/dir.html.

Compliance Monitoring Tools and Procedures

MRO uses 32 primary tools to execute its audits, four of which are highlighted in this section. A key guidance source for MRO is GAGAS, which provides a framework for conducting quality audits. MRO's primary audit template tool for documenting audit procedures, testing, findings and reports is its *Audit and Spot Check Process and Procedures* dated May 2012. This document consists of 31 templates and serves as a detailed roadmap and reference tool for MRO's Compliance staff to use during Operations and Planning and CIP audits as well as spot checks. The audit team also uses an FSAW audit workbook which is an MRO-specific tracking tool built on the RSAW for documenting audit work.[42] This tool facilitates evidence requests from registered entities as well as tracking of Reliability Standards to ensure that an audit proceeds in a timely fashion. This tool was updated in 2013 prior to its incorporation into the Auditor Manual.

MRO's web Compliance Database Management System (webCDMS) is also central to its compliance monitoring efforts. WebCDMS assists registered entities in documenting and submitting compliance information. The database provides multiple functionality including:

(1) Viewing Regional Entity and NERC requirements per a registered entity's function(s);

(2) Reviewing compliance information prior to submittal;

(3) Submitting compliance documentation;

(4) Generating compliance reports; and

(5) Tracking mitigation plans.

The webCDMS tool previously required each registered entity to use different logins and passwords. A recent enhancement to webCDMS provides the ability for a registered entity to logon and access webCDMS on behalf of multiple affiliated entities within a particular Regional Entity, using a single username, password, and webCARES digital certificate.

Quality Assurance

MRO relies on a number of tools to assist in its quality assurance efforts. Compliance staff perform peer reviews of audit documentation during audit fieldwork, in addition to reviews conducted by management and by non-Compliance personnel. Such reviews ensure the completeness of audit documentation and that any findings are consistent with the elements of a finding per GAGAS. In addition to audit documentation reviews, Compliance staff rely on "lessons learned" discussions and post-audit surveys of registered entities to help identify opportunities to improve compliance monitoring-related processes and to improve future interactions with registered entities. Finally, Compliance staff review audit findings with Risk Assessment and Mitigation staff to ensure consistent application of the NERC Reliability

[42] FRCC and WECC also have tools that mirror this tool.

Standards among MRO staff and across registered entities in the MRO footprint. All lessons learned are shared internally and, if more broadly applicable outside of MRO, with personnel from NERC and other Regional Entities.

Guidance and Training for Industry Stakeholders

MRO supports industry in developing compliance guidance in the form of Application Guides. Application Guides offer non-binding, training guidance regarding how to meet the requirements of existing and emerging Reliability Standards. They can include the following:

(1) Presentation materials developed by MRO member organizations who volunteer SMEs to the NERC SC;

(2) FERC comments relating to a Reliability Standard;

(3) Documentation and evidence demonstrating compliance; and

(4) References and source documents related to laws, policies, directives, instructions, Reliability Standards and guidelines.

MRO tracks the impact of Application Guides through trend analysis of Reliability Standard violations.

MRO's website contains posted compliance guidance directed to industry stakeholders, including content about internal controls, best practices for internal compliance programs, and aids to assist in compliance for specific and more challenging Requirements. Instructional materials informing stakeholders as to what they can expect and what professional audit standards they should anticipate for their compliance audits is made available on this site. Guidance is also offered to registered entities in their audit notification packets from MRO. With regard to small entities, MRO routinely communicates to the representatives of the applicable trade associations that their members should contact MRO directly with any concerns, including regulatory burden.

MRO holds at least two one-day workshops per year addressing reliability, compliance, and enforcement. In 2013, MRO also held a model building workshop to provide direction and instruction for those who are directly involved in the preparation and submittal of model data. MRO's bi-monthly newsletters have a regular column titled "Tips and Lessons Learned" which covers a wide range of topics from how to use webCDMS more effectively to changes in the procedures for requesting and processing TFEs. Occasionally, "Tips and Lessons Learned" are authored by registered entities covering topics like the CIP Version 5 transition study. MRO conducted its first webinar in 2014 and as part of its review of training initiatives, MRO will be asking its stakeholders for input on the use of webinars. MRO is not participating in any initiative with other Regional Entities to decrease or consolidate the number of announcements published for industry; however, MRO reports that in response to its stakeholder surveys, registered entities have generally encouraged MRO to communicate more, not less.

Maintaining Confidentiality

There are strict confidentiality requirements associated with all CMEP activities.[43] MRO follows the CMEP to maintain the confidentiality of any complaint and has a third-party hotline available to complainants to maintain anonymity. Complainants can contact MRO's chief compliance and ethics officer, who does not do any CMEP work, to maintain anonymity.

All data related to MRO's CMEP activities, particularly registered entity data that may be designated Critical Energy Infrastructure Information, are protected according to §1500 of the NERC ROP to ensure that confidentiality is maintained. Data is stored on a restricted network drive, to which access is granted on a need-to-know basis according to individuals' job responsibilities. Outside of the restricted drive, data may only be stored for limited periods of time on encrypted hard drives or IronKey-encrypted USB drives. When transferring data to or from registered entities, MRO makes use of a secure Enhanced File Transfer (EFT) server, which includes encryption both during transfer and while stored on the EFT server. The EFT server is also utilized for all data transfers involving NERC, FERC, or other Regional Entities.

Participation in RAI

As part of RAI, NERC has assisted with ensuring consistency among audits conducted by the Regional Entities by developing the Auditor Manual. MRO has already taken steps to follow the protocols established in the Auditor Manual. In particular, MRO has changed its protocol regarding independence of audit staff to conform to GAGAS. MRO has also indicated that it will fully adopt the Auditor Manual protocols.

iv. Northeast Power Coordinating Council, Inc.

Department Structure / Staffing / Conflict of Interest Avoidance

Activities performed pursuant to the CMEP are performed within the NPCC Compliance Monitoring and Enforcement and Organization Registration and Certification (CORC) program. In total, NPCC's CORC program area consists of 16 employee positions. The CORC program is divided into two subprograms: (i) an Audits and Investigations subprogram and (ii) a Registration and Enforcement subprogram. The Audits and Investigations subprogram conducts audits, spot checks, and compliance investigations. It is comprised of eight staff employees. The Audits and Investigation subprogram utilizes approximately a dozen independent consultants in addition to NPCC employees. During an audit, spot check, or compliance investigation, the Audits and Investigation team makes a determination of whether a registered entity has any possible violations of NERC Reliability Standards, and provides NPCC enforcement staff with a final report.

The Registration and Enforcement subprogram is comprised of eight staff employees. The Registration and Enforcement subprogram reviews the audit, spot check, or compliance investigation report, and makes an independent evaluation of the facts and circumstances surrounding each possible violation identified in the report. Registration and Enforcement will

[43] *See* NERC ROP §402.8 (NERC Oversight of the Regional Entity Compliance Monitoring and Enforcement Programs — Confidentiality).

determine whether sufficient evidence supports each possible violation and will work with the registered entity to develop an effective and comprehensive mitigation plan. Registration and Enforcement will also evaluate the appropriate enforcement actions, including sanctions and/or penalties.

Many NPCC audit team members individually have over 30 years of industry experience. Two audit team members are NERC-certified system operators and two are registered professional engineers. As described above, NPCC also relies on independent SME consultants who have no other industry obligations or conflicts of interest to perform compliance monitoring activities and to support any increases in its workload. NERC AAO staff recommends that NPCC consider having more audit staff become NERC-certified system operators.

NPCC audit team members participate in various auditor training sessions and workshops. All NPCC auditors attend at least one of the two annual NERC ERO compliance workshops to keep apprised of current topics and NERC initiatives affecting compliance. NPCC itself conducts four in-house auditor training sessions each year. In addition, NPCC auditors augment their training with annual required or suggested NERC training.

With respect to monitoring compliance with the CIP Reliability Standards, NPCC recruits employees with network systems protection experience. Two NPCC auditors have CISSP certifications and one auditor has physical security protection experience. NPCC examines the training that these auditors will need for the upcoming year or other future time frame and assures that its CIP auditors (both employees and consultants) receive the appropriate supplemental training, in addition to the regular training described above.

NPCC has adopted policies and procedures to avoid conflicts of interest in its CMEP work and to maintain the independence of its compliance staff. Those policies and procedures provide that each NPCC director, officer, and employee shall: (i) avoid and refrain from involvement in situations where there is an actual conflict of interest; (ii) disclose any actual or potential conflicts of interest that may arise; (iii) recuse himself or herself from participation in any action involving an actual or potential conflict of interest; and (iv) refrain from voting on any actions where there is an actual or potential conflict of interest.

Compliance Monitoring Tools and Procedures

NPCC utilizes a number of tools to execute its audits, several of which are highlighted in this section. NPCC instituted an improved process in order to facilitate its data reviews in both pre-audit and on-site phases. Its pre-audit process involves several rounds of questions and answers between NPCC and the registered entity relating to a subset of Reliability Standards within the audit scope. The NPCC auditor catalogs the data requests in an evidence tracking spreadsheet. Following this initial evidence review, NPCC provides the evidence tracking spreadsheets to the registered entity prior to on-site activities. During the on-site portion of the audit, the evidence tracking spreadsheets are used by the audit team to direct SME interviews and record additional questions and data requests determined throughout the interview process. NPCC also developed a change management process to ensure the integrity of evidence tracking spreadsheets. At the end of each day of the audit, the NPCC audit team reviews the updated evidence tracking spreadsheets with the registered entity in a debrief.

NPCC's Compliance Data Administration Application (CDAA) is central to its compliance monitoring efforts. All registered entities in NPCC are required to use the CDAA to submit self-certifications and self-reports. Information submitted into the CDAA is automatically placed into CITS. The CDAA database provides multiple functionality, including:

(1) Viewing Regional Entity and NERC requirements per a registered entity's function(s);

(2) Reviewing compliance information prior to submittal;

(3) Submitting compliance documentation;

(4) Generating compliance reports; and

(5) Tracking mitigation plans.

Quality Assurance

NPCC's audit processes are documented in its compliance procedures; these procedures are reviewed on a periodic basis.[44] Following the conclusion of every on-site and off-site audit, NPCC asks registered entities to complete a feedback form. NPCC's audit group reviews comments in order to assess how to improve its processes. NPCC chooses to include detailed information and justification for all audit conclusions in the nonpublic audit reports, including "No Finding" and "Not Applicable." NPCC performs a quality check of draft reports prior to sending them to registered entities for comment. As a result, NPCC does not always meet the 60-day timeline for issuance of audit reports. Additionally, in 2013, NPCC began assigning a minimum of two auditors, in addition to the audit manager, to each off-site audit. This allows the auditors to learn from each other and provides additional quality assurance. Prior to 2013, NPCC assigned a minimum of one auditor, in addition to the audit manager, to each off-site audit.

Guidance and Training for Industry Stakeholders

Since 2009, NPCC has provided the same level of resources for its Training, Education, and Operator Certification program. NPCC dedicated 0.1 FTE to its Training, Education, and Operator Certification program in 2009.[45] For 2013, NPCC also dedicated 0.1 FTE to this program.[46] NPCC utilizes its semi-annual standards and compliance workshops as its main mechanism for outreach to its registered entities, and these activities are budgeted in those respective program areas. NPCC also conducts webinars open to all NPCC registered entities on an as-needed basis. It also posts question-and-answer documents on its website as appropriate. NPCC responds to individual requests from registered entities, but if an individual concern can be applied to all registered entities, NPCC will post a *Compliance Guidance Statement* or clarification

[44] Available at: https://www.npcc.org/Compliance/Compliance%20Procedures/Forms/Public%20List.aspx.

[45] 2009 Business Plan and Budget, Northeast Power Coordinating Council, Inc., June 24, 2008.

[46] 2013 Business Plan and Budget, Northeast Power Coordinating Council, Inc., June 26, 2012.

to address that concern. NPCC hosts regular stakeholder-based Compliance Committee meetings to disseminate the latest information regarding the compliance program to industry stakeholders. Many of these regularly-scheduled meetings are hosted on a web conferencing platform to enable broad and cost-effective participation. NPCC also developed an internal entity guide to assist registered entities in meeting quarterly reporting requirements pursuant to PRC-004 and NERC ALR4-1.

In 2013, NPCC implemented a Physical Security Outreach program. Under this program, NPCC physical security SMEs performed physical security assessments for registered entities that have requested such assistance. NPCC has developed a new Cyber Security Outreach program for 2014.

Maintaining Confidentiality

There are strict confidentiality requirements[47] associated with all CMEP activities. NPCC follows the CMEP and §1500 of the NERC ROP to maintain the confidentiality of all confidential CMEP-related activities. Additionally, NPCC staff involved in CMEP-related activities have signed confidentiality agreements.

Participation in RAI

As part of the RAI initiative described in NERC's *Overview of NERC Activities and Accomplishments in the Five-Year Period*, NPCC participated in efforts to develop the Auditor Manual for the ERO. NPCC also participated in the RSAW Working Group to ensure commonality on audit approaches to the NERC Reliability Standards. NPCC senior management participated in the RAI workgroups charged with developing a framework for Entity Risk Assessment and Internal Control Assessment. NPCC also participates in various Regional Entity compliance and enforcement groups to further consistency in compliance applications across the Regional Entities.

v. ReliabilityFirst Corporation

Department Structure / Staffing / Conflict of Interest Avoidance

During the assessment period, three departments carried out ReliabilityFirst's CMEP functions: (i) Compliance Audits (handling audits and spot checks of compliance with Reliability Standards by registered entities);[48] (ii) Investigations and Compliance Services (handling compliance investigations, registration and certification, self-certifications and periodic data submittals, complaints, and industry training); and (iii) Enforcement (handling all aspects of

[47] *See* ROP §402.8 (NERC Oversight of the Regional Entity Compliance Monitoring and Enforcement Programs — Confidentiality).

[48] Upon the implementation of the CIP Reliability Standards, Compliance Monitoring was subdivided into a CIP Compliance Audit department and an Operations and Planning Compliance Audit department.

enforcement actions, including fact and circumstance review, risk-harm assessment,[49] mitigation plan review and validation, and the negotiation and drafting of settlements and final disposition documents).

At the beginning of 2014, ReliabilityFirst reorganized its compliance structure in order to more clearly focus around risk and to support RAI. Presently, ReliabilityFirst's Compliance Monitoring group handles compliance audits, spot checks, investigations, and complaints, and is subdivided into two departments: (i) a CIP Compliance Monitoring department and (ii) an Operations and Planning Compliance Monitoring department. ReliabilityFirst created a new Reliability Assurance and Monitoring group, which is comprised of three departments: (i) Entity Development (which conducts assist visits, appraisals, certifications, and entity training); (ii) Risk Analysis & Mitigation (which conducts risk-harm assessments, handles mitigation activities, and conducts risk-based assessments, event analyses, and analytics); and (iii) Standards and Services (which is responsible for Reliability Standards, registration, self-certifications and data submittals). ReliabilityFirst's Enforcement group is now housed under Legal & Regulatory Affairs.

ReliabilityFirst's Compliance department (consisting of the Compliance Monitoring and Reliability Assurance and Monitoring groups) consists of 33 positions. Many employees within those positions have at least 15 years of industry experience. Additionally, many of ReliabilityFirst's compliance staff are registered professional engineers, and many are NERC-certified system operators. ReliabilityFirst's CIP auditors have extensive experience in information technology and cybersecurity and hold various security, audit, and IT certifications.

ReliabilityFirst requires regular training for its Compliance staff. ReliabilityFirst's Compliance Audit Procedure has specific training requirements that its audit team members must complete prior to attending an audit. ReliabilityFirst audit team participants and ReliabilityFirst observers must complete all required NERC auditor training courses. All ATLs must complete the *Fundamentals of Auditing for NERC Compliance Team Leaders* and *Gathering Quality Evidence* modules. All other audit team participants must complete the *Fundamentals of Auditing for NERC Compliance Audit Team Members* and *Gathering Quality Evidence* modules. Audit team members participate in various auditor training sessions and workshops. ReliabilityFirst sends its auditors to NERC-led training events whenever they occur. ReliabilityFirst also holds its own staff training week during which it provides on-site training to all staff members, including auditors. For example, during the 2013 ReliabilityFirst training week, ReliabilityFirst's Operations and Planning auditors received training on protection systems, while its CIP auditors received training on various cybersecurity issues. All auditors received training on the evaluation and communication of risk and using risk-based criteria in informed decision-making.

ReliabilityFirst has adopted policies and procedures to avoid conflicts of interest in its CMEP work in order to maintain the independence of its compliance staff. All ReliabilityFirst employees, contractors, and directors are governed by the ReliabilityFirst *Conflict of Interest Policy*, the *ReliabilityFirst Code of Business Conduct and Ethics*, and §1500 of the NERC ROP.

[49] To enhance its risk determination process in enforcement, ReliabilityFirst developed a risk-harm assessment process which, among other things, requests technical experts to answer a series of questions about the risk and harm posed by each violation using a common scale to ascertain a quantified risk assessment.

Its employees and contractors must sign and adhere to nondisclosure and confidentiality agreements and complete conflict of interest forms. ReliabilityFirst does not allow stakeholder participation in its compliance or enforcement activities. Further, ReliabilityFirst does not allow its industry sector directors to participate in settlement discussions with ReliabilityFirst on behalf of their Registered Entity.[50]

Compliance Monitoring Tools and Procedures

ReliabilityFirst utilizes a number of tools to execute its audits, several of which are highlighted in this section. During the assessment period, ReliabilityFirst implemented changes to its compliance monitoring processes and tools to ensure that they are consistent with NERC guidance, other Regional Entities, and GAGAS.

Most entities in the ReliabilityFirst footprint utilize an application called "Color-Code-It" to make evidence submittals which saves audit teams considerable review time and helps ensure a comprehensive and a focused audit or spot check. Use of this application also allows registered entities to organize and monitor their own compliance, maintain internal controls, and reduce the burden of compliance monitoring.

ReliabilityFirst uses a pre-audit review period to review evidence submittals, seek additional information, make compliance determinations, and develop a focused requirement listing to be addressed at the audit review. Audit reviews are typically scheduled two to three weeks prior to the audit. ReliabilityFirst believes that this improvement has provided the time to do a very comprehensive audit and maintain focus on items which need more attention or clarification.

During the assessment period, ReliabilityFirst began to develop and implement an audit management system. This system will allow ReliabilityFirst to manage audits, spot checks, and potentially other monitoring processes of an entity in one application. The software resembles a project management system and has been developed to follow the various steps of an audit checklist, such as planning, pre-audit review, production, reporting and metrics. This system provides auditors with a structured format to follow and help to ensure consistency and completeness in each audit that is performed.

ReliabilityFirst has developed and implemented a risk-based assessment process. This process was initiated in June 2011. During the risk-based assessment process, a designated cross-functional team[51] conducts a risk assessment of a registered entity and makes recommendations to help shape the scope and focus of the registered entity's upcoming compliance audits and/or spot checks. During the assessment, the team evaluates the potential impact of the registered entity on the BPS based upon various factors, including the registered entity's registration, size, location, technical characteristics (e.g., existence of special protection systems), organizational makeup, compliance history and culture, and trends and emerging risks in the industry. ReliabilityFirst implemented this process based on guidance from NERC. ReliabilityFirst will refine the risk-

[50] *See* 2014 Joint Regional Entity Self-Assessment (JRESA) Appendix 2-C at 21.

[51] This cross functional team includes representatives from the ReliabilityFirst engineering, compliance audit, compliance enforcement, and reliability assurance departments.

based assessment process further throughout 2014 to develop a comparable, repeatable process that is aligned with efforts being undertaken under RAI.

ReliabilityFirst's webCDMS system is central to its compliance monitoring efforts. ReliabilityFirst uses webCDMS as its information management tool to collect securely, track, and monitor compliance information from its registered entities. The database provides multiple functionality including:

(1) Linking Regional Entity and NERC requirements to a registered entity's function(s);

(2) Allowing registered entities to review compliance information prior to submittal;

(3) Allowing registered entities to submit compliance documentation, including self-reports, self-certifications, and mitigation plans;

(4) Allowing ReliabilityFirst and registered entities to generate compliance reports; and

(5) Allowing ReliabilityFirst to track mitigation plans.

Quality Assurance

ReliabilityFirst's quality assurance processes are contained within its internal compliance procedures, which ReliabilityFirst reviews on a periodic basis. The ReliabilityFirst Audit Procedure requires ReliabilityFirst to follow a multi-layered quality review process for its draft audit reports, which includes peer reviews and management reviews. The ReliabilityFirst Audit Procedure also requires ReliabilityFirst to ask entities to provide feedback on the audit process and any other concerns they may have, using a feedback form. ReliabilityFirst then uses the feedback and concerns for quality assurance and continuous improvement.

Guidance and Training for Industry Stakeholders

Since 2009, ReliabilityFirst increased its training resources for its Training, Education, and Operator Certification program, which provides continuing education hours through the NERC Continuing Education program. ReliabilityFirst dedicated 0.05 FTE to its Training, Education, and Operator Certification program in 2009.[52] For 2013, ReliabilityFirst increased training resources to 3.1 FTEs.[53]

ReliabilityFirst uses several different methods to communicate with and train its registered entities. ReliabilityFirst has implemented an "Assist Visit" program. Under this program, a registered entity may request a one-on-one or small group meeting where ReliabilityFirst provides guidance on compliance-related activities. Assist Visits can be in the form of a conference call, web meeting, or on-site visit, and topics can range from helping a registered entity become more

[52] 2009 Business Plan and Budget, ReliabilityFirst Corporation, August 13, 2008.

[53] 2013 Business Plan and Budget, ReliabilityFirst Corporation, June 22, 2012.

familiar with general compliance-related material and activities to specific guidance on an area of concern. ReliabilityFirst has prepared and implemented an internal policy and procedure that requires it to internally document Assist Visit training activities to extrapolate and share generic lessons learned where appropriate. The policy and procedure ensures that ReliabilityFirst documents its Assist Visit training activities in a uniform manner, which will help it better distill Assist Visits into useful lessons learned to share with ReliabilityFirst stakeholders where appropriate.

ReliabilityFirst also provides a monthly newsletter to approximately 600 compliance contacts at its registered entities. This newsletter provides registered entities with news and information relating to reliability and compliance activities. In addition, ReliabilityFirst provides a monthly compliance update letter that provides the registered entities with any changes made to the compliance monitoring schedule and the due dates of compliance submittals. ReliabilityFirst's public website provides a number of compliance and technical materials to assist registered entities in their compliance program implementation.

ReliabilityFirst also hosts bi-annual compliance workshops and periodic webinars throughout the year to train registered entities on compliance processes, reliability initiatives, and the Reliability Standards. In addition, ReliabilityFirst holds a monthly conference call with web presentation capabilities for registered entities; this monthly call is an open forum for registered entities to voice concerns, ask questions, and receive information.

Maintaining Confidentiality

ReliabilityFirst has a variety of security measures in place that are designed to protect confidential compliance information. All ReliabilityFirst laptops have encrypted hard drives, minimizing the risk of confidential information being disclosed in the event of a lost or stolen laptop. ReliabilityFirst requires employees to change the passwords on their laptops every 90 days, and requires work phones to be password protected. ReliabilityFirst's offices have physical security measures including badge readers and access badges for all employees. Visitors must be escorted by ReliabilityFirst employees in nonpublic areas of the offices.

ReliabilityFirst uses a confidential and secure extranet website to exchange documents with a registered entity during a compliance monitoring process or an enforcement action. To provide another layer of protection, ReliabilityFirst encrypts sensitive documents.

There are strict confidentiality requirements[54] associated with the investigation of any complaints regarding such potential violations of Reliability Standards. ReliabilityFirst follows the CMEP to maintain the confidentiality of any complainant and maintains a complaint reporting form on its web page.

[54] *See* NERC ROP §402.8 (NERC Oversight of the Regional Entity Compliance Monitoring and Enforcement Programs — Confidentiality).

Participation in RAI

ReliabilityFirst participated in the conceptualization, development, testing, and integration of several RAI programs. ReliabilityFirst led a series of pilot programs to test the evaluation of internal controls at registered entities using an appraisal process. As part of the RAI, ReliabilityFirst participated in efforts to develop the Auditor Manual. ReliabilityFirst also participated in the RSAW Working Group to ensure commonality on audit approaches to the NERC Reliability Standards. In the enforcement area, ReliabilityFirst staff participated in the Aggregation of Minimal Risk Issues pilot program, maintaining the sole MRRE log. Additionally, ReliabilityFirst staff participated in the Enforcement Discretion pilot program and served on the *ERO Self-Report User Guide* and *ERO Enterprise Mitigation Plan Guide* drafting teams. Further, ReliabilityFirst staff participated in the process to develop improvements for the compliance and enforcement oversight of MRREs. Finally, ReliabilityFirst participates in various Regional Entity compliance and enforcement groups to further consistency in compliance applications across the Regional Entities.

vi. SERC Reliability Corporation

Department Structure / Staffing / Conflict of Interest Avoidance

SERC's CMEP function is split into two departments, (i) Compliance and (ii) Enforcement, each with its own assigned personnel. SERC Compliance staff utilize off-site and on-site audits, spot checks, and other compliance monitoring methods to assess registered entity compliance with NERC Reliability Standards. Compliance is also responsible for registering users, owners, and operators of the BPS and for certifications. Compliance staff prepare detailed reports on each audit and make recommendations to Enforcement about possible violations of NERC Reliability Standards.

SERC Enforcement staff undertake an independent review of the facts and circumstances surrounding each possible violation discovered by Compliance staff or through the other discovery methods. If a sufficient basis exists, then Enforcement staff determine the complete scope of the violation and the actual and potential risk to the reliability of the BPS. The segregation of duties between Compliance and Enforcement staff establishes independence between those making the findings and those determining and negotiating penalties and sanctions.

In 2009, SERC had six Operations and Planning auditors and two CIP auditors. In 2014, SERC has seven Operations and Planning auditors and eight CIP auditors. SERC Operations and Planning audit team members possess the education, industry experience and technical expertise in planning and real-time operations necessary to conduct audits. Several of the Operations and Planning auditors are NERC-certified system operators. Many of the SERC CIP audit team members possess physical security or information security credentials, professional engineering licenses, and/or industry experience. For Operations and Planning audits, SERC audit teams work in two groups. One group reviews audit evidence for NERC operations Reliability Standards and the other group reviews evidence for planning Reliability Standards. For CIP audits, SERC audit teams also work in two groups. One group reviews evidence for physical security Reliability Standards and the other group reviews evidence for cybersecurity Reliability Standards. Each group has a lead moderator and a scribe.

SERC uses industry subject matter experts (ISMEs) from various registered entities that are members of SERC as participants in the audit team. The ISMEs help the audit team to review evidence, and provide insight into issues that the audit team may encounter throughout the audit process. While ISMEs are involved in every aspect of the audit, including interviews of the audited entity's SMEs, they are not voting members of the audit team. ISMEs bring knowledge of the latest changes that are occurring within industry and in the individual ISME's organization. ISMEs are required to sign nondisclosure agreements and complete a conflict of interest form. SERC reviews the conflict of interest forms before assigning ISMEs to audits. If a conflict exists or there is the appearance of a conflict, SERC will assign an ISME to an audit of a different registered entity.

SERC audit team members participate in various SERC internal auditor training sessions, consultant-provided auditor training sessions, NERC auditor training modules, NERC audit team lead training, and ERO auditor workshops. NERC uses training accountability databases to confirm the credentials of audit team members. SERC requires all audit team members to complete "Just-In-Time" training if the audit team member has not completed appropriate training in the last 90 days. The purpose of this training is to refresh fundamental concepts of auditing and thereby supplement that which is required by NERC. This additional training is an excellent method to re-enforce the importance of quality evidence and documentation during the audit process.

Cross-training is also an important feature of auditor training at SERC. Early in the assessment period, SERC utilized CIP auditors as scribes during Operations and Planning audits so that the CIP auditors would have an opportunity to learn the audit process and approach with Operations and Planning Reliability Standards. SERC auditors have also participated on audit teams in other Regional Entity footprints to cross-train and learn.

To determine the skill level required for auditors, SERC relies on feedback from existing audit staff, the input and experiences of NERC and the other Regional Entities, and changes in the Reliability Standards and industry. SERC anticipates training needs by looking at gaps that exist in the audit teams and focuses training on addressing those gaps. SERC considers the direction in which the ERO and other Regional Entities are moving and, if needed, adapts its training plans and desired skill sets to address those needs. SERC also considers new or revised Reliability Standards and the audit approaches associated with them, and provides training if necessary. SERC also listens to what the auditors identify as useful training and development opportunities and allows them to pursue relevant opportunities to strengthen their skills.

SERC has a documented conflict of interest policy which applies to all SERC staff. The conflict of interest policy requires SERC staff to provide an annual update of any employment or director or officer relationships with SERC registered entities, financial interests in any businesses from the energy sector other than SERC, and any business relationships with energy sector businesses other than SERC by the SERC employee or members of the employee's immediate household. SERC personnel with a financial interest in a registered entity or any other current conflict are not allowed to review, discuss, or participate in compliance or enforcement activities.

Compliance Monitoring Tools and Procedures

SERC utilizes a number of tools to execute its audits, several of which are highlighted in this section. As an overarching procedure in completing and tracking the audit progress, SERC uses its audit event tracking spreadsheet. In this spreadsheet, SERC details the actions required to successfully administer an audit and notes the completion of milestones. Registered entities use an internet-based portal for the transmission of audit information and the audit RSAWs and pre-audit questionnaires. During on-site audits and throughout the period leading up to the audit, SERC utilizes email notifications, worksheet summaries, and spreadsheet tables for tracking the review of evidence and for delivering updates to the registered entity and audit team members. SERC also uses established ERO auditor tools, including the RAT-STATS sampling tool and RSAWs. SERC also uses a pre-populated spreadsheet to document the review status for each requirement, including data requests and follow-up questions to be asked on-site. The SERC audit team uses a tool called an audit workbook. This workbook accounts for each of the Reliability Standards and associated requirements that compose the audit scope, any outstanding data requests, and a list of ongoing findings by the audit team.

Until 2013, SERC did not perform formal pre-audit reviews. The absence of a formal pre-audit review is an area of concern because formal pre-audit reviews and the opportunity to thoroughly review documentation would provide SERC with more time to investigate exceptions to audit procedures. It also helps to ensure that sufficient evidence is collected. In 2013, SERC began conducting pre-audit reviews of evidence submittals, which allowed audit teams to better prepare for audits and seek additional information as needed before arriving on-site. Audit reviews are typically scheduled two to three weeks prior to an audit. These efforts have allowed SERC to reduce its time on-site, thereby reducing the burden on the registered entity, and ensure that the on-site audit focuses less on preliminary data collection and more on reviewing higher risk issues and areas where additional clarification is needed.

While SERC has a comprehensive process for registered entity assessment and audit scoping, the associated documentation supporting this process was not thorough until recently. Maintaining thorough audit scoping documentation is an auditing best practice per GAGAS. Adequate scoping helps justify auditng the areas that pose potential risk to the BPS. Starting in mid-2013, SERC conducts an inherent risk assessment and internal controls review (if appropriate) of the registered entity to determine the audit scope and scale. This includes a review of registered entity compliance history, events and misoperations history, registered entity specific data, regional factors affecting reliability, legal or regulatory issues affecting compliance, and public information about the reliability impact of the registered entity. Detailed audit scoping will enable SERC management to better supervise and assess audits. SERC is now actively working to build GAGAS audit principles into its audit process. SERC's sampling methodology could be improved by integrating NERC's *Sampling Methodology Guidelines and Criteria* in order to avoid inconsistency in identifying and quantifying population, sample sizes, sample selection and lack of documentation memorializing sampling procedures and to avoid incorrect conclusions.

SERC tracks mitigation plans in CITS, a compliance information tracking system used by SERC, FRCC, and NPCC. CITS allows SERC to track mitigation plans submitted by registered entities, any revisions requested by SERC, and certifications of mitigation plan completion. SERC works with registered entities to answer questions about SERC's expectations for mitigation plans

and encourages them to submit mitigation plans in a timely manner. SERC occasionally asks registered entities to submit revised mitigation plans when the proposed mitigation plan milestones would result in an extended period of noncompliance that would pose an additional risk to the reliability of the BPS.

SERC presently is unable to consolidate its compliance and reliability assessment portals because they are hosted on separate systems. SERC is exploring an enhancement to these portals that that will provide a registered entity with a summary of all forms (Compliance, Reliability Assessments, and Reliability Services) due for that entity. This will allow users to navigate between both portals to complete the required filings.

SERC develops an annual reporting schedule which identifies required periodic data submittals. Once the matrix is developed, SERC posts it to its website and Compliance Portal, and notifies its registered entities. The Compliance Portal automatically assigns the applicable periodic data submittals to each registered entity's portal site, based on the schedule, identifying the due dates. SERC monitors the submittal of each periodic data submittal using a reporting tool and issues a notification to the registered entity's designated contacts for any periodic data submittals that have not been submitted to SERC. The data received from the periodic data submittals are reviewed and any potential noncompliance issues are documented and reported to Enforcement.

Quality Assurance

SERC's internal process requires a management review within two weeks of an audit engagement, and prior to the audit exit briefings before a decision is made with respect to the registered entity's compliance with NERC Reliability Standards. The management review evaluates the significant judgments made by the audit team and the related conclusions reached in forming the overall conclusion on the engagement. SERC Enforcement staff reviews the audit team's findings of noncompliance and makes a final determination before notifying the registered entity and NERC of any possible violations.

SERC Compliance staff meet weekly and discuss lessons learned after each audit. If appropriate, a plan is developed for any areas that need changes or improvements internally. SERC also develops lessons learned as part of its outreach efforts and these are shared with registered entities. The Operations and Planning and CIP audit groups each have a point of contact for their respective areas who are made aware of any trends or important information that they feel should be communicated to SERC registered entities. A brief description and observations are written and posted quarterly on a dedicated area of the SERC website where registered entities can review it.

SERC has a document retention policy that requires audit documents be maintained for seven years. SERC has a document management system with a retention policy service that allows for the configuration of retention policies. The system also requires administrative permissions to delete documents, files, and folders.

Guidance and Training for Industry Stakeholders

Since 2009, SERC increased its training resources for its Training, Education, and Operator Certification program, which provides continuing education hours through the NERC Continuing

Education program. SERC dedicated 1.4 FTE to its Training, Education, and Operator Certification program in 2009.[55] In 2013, SERC delivered its training program through 2.41 FTEs.[56]

A catalog of all SERC outreach and training has been posted to the home page of the SERC website. Three compliance seminars are held annually with one focused exclusively on CIP topics. In addition, periodic Open Forum WebEx sessions are scheduled along with focused webinars on new and/or revised Reliability Standards and changes in regulatory policy such as the new BES definition process. Specific training on SERC policy changes and enhancement to tools offered to registered entities is also conducted on an as-needed basis. The majority of outreach events are offered via WebEx, and recordings are posted to the SERC website. Select events also offer the opportunity to attend in person and/or earn continuing education hours.

The SERC Training, Education, and Operator Certification program provides education and training necessary to understand and operate the BPS. The target audience of the program is BPS operating personnel – including system operations personnel, operations support personnel (engineering and information technology), supervisors and managers, and training personnel. The program held four system operator conferences in 2013, a wide area restoration drill, and several standard-focused webinars and workshops. The program also supports SERC staff training and development as well as the administration of records necessary to maintain status as a NERC continuing education provider. The majority of outreach events are offered via WebEx, and recordings are posted to the SERC website. Select events also offer the opportunity to attend in person and/or earn continuing education hours.

SERC outreach has conducted small entity workshops specifically focusing on topics of interest to smaller registered entities. An informal group consisting of representatives from four small entities is consulted as to what topics are appropriate and of interest to them. The annual *SERC Filing Due Dates* document is posted to the SERC website in Excel format to make it easy for entities to sort by registered function in order to determine what compliance filings are due and when. An email address (serccomply@serc1.org) is available, and publicized in all outreach materials, for entities to contact SERC with any questions they may have.

Maintaining Confidentiality

SERC has a variety of security measures in place that are designed to protect confidential compliance information. All SERC laptops have encrypted hard drives, minimizing the risk of confidential information being disclosed in the event of a lost or stolen laptop. SERC requires employees to change the passwords on their laptops every 90 days. SERC requires work phones to be password protected and these phones can be remotely wiped. SERC's offices have physical security measures including badge readers, access badges for all employees, and video cameras at all entrances and exits. Visitors must be escorted by SERC employees in nonpublic areas of the offices.

[55] 2009 Business Plan and Budget, SERC Reliability Corporation, July 9, 2008.

[56] 2013 Business Plan and Budget, SERC Reliability Corporation, July 11, 2012.

In addition, SERC implemented a Protected Entity Information (PEI) program in 2012 to handle confidential CIP information and other protected entity information. This PEI program was implemented in order to allow registered entities to provide SERC with CIP and other confidential information without SERC having to visit registered entities' sites. The PEI program protects this information using standards at least as strict as those in the CIP Reliability Standards. Access to PEI information is restricted to those SERC employees with a need to know who have taken cybersecurity awareness training within the past year and have passed SERC-initiated background checks within the previous seven years. In addition, SERC logs and controls physical access to the hardware used for the PEI program. SERC also logs and controls electronic access to the PEI information stored on that hardware, which is encrypted at rest.

Participation in RAI

A key focus of SERC's strategic plan for 2013-2015 is to develop, advocate, and support RAI. SERC has established a plan to implement audit function structural improvements to produce more effective, efficient audits that recognize BPS reliability risk. By incorporating risk principles in the planning and execution of compliance engagements, in conjunction with broader RAI outcomes, the focus of SERC and its registered entities will shift towards identification and mitigation of risks to reliability – preventing uncontrolled, unplanned cascading events. Scoping and timing of monitoring activities will move from a mechanical approach (fixed set of entities monitored for a pre-established set of Reliability Standards on a pre-defined frequency) to a risk-based approach customized around SERC-specific reliability issues and tailored to the specific registered entity. Through more extensive information analysis and dialogue with registered entities, SERC staff will seek to fully understand risk and the registered entity's management practices and controls employed to obtain reasonable assurance of the reliable operation of the BPS. Based on this more proactive review and assessment, SERC will adjust the scope and frequency of its compliance monitoring activities with respect to the specific registered entity.

Throughout 2013, SERC worked with an inter-regional team to develop the *Compliance Auditor Handbook* that describes a uniform process for implementing the *Compliance Auditor Checklist*. In addition, SERC piloted a new approach to risk assessments and auditing practices that permits more focused attention and resources on those issues that present the greatest risk to the BPS. Currently, SERC is working with all eight Regional Entities to develop a common methodology to identify and assess risk in a manner consistent with GAGAS criteria.

vii. Southwest Power Pool Regional Entity

Department Structure / Staffing / Conflict of Interest Avoidance

The SPP RE CMEP is administered by the SPP RE direct staff organized into three groups: (i) Compliance Monitoring - Operations and Planning; (ii) Compliance Monitoring - CIP; and (iii) Enforcement. The Compliance groups are responsible for registering BPS owners, operators, and users, and monitoring and assessing registered entity compliance with the approved Reliability Standards. The Compliance groups make the initial determination of a registered entity's compliance or noncompliance by performing audits, spot checks, and reviews of self-identified violations. The SPP RE Enforcement group reviews the Compliance groups' findings of noncompliance, notifies registered entities and NERC of possible violations, reviews and verifies

registered entity mitigation plans, determines proposed monetary penalties and non-monetary sanctions, and participates in settlement negotiations. To meet its RDA and ROP obligations and its goals, SPP RE has increased its Compliance and Enforcement staff and its budget.

All SPP RE auditors are required to attend various SPP RE internal auditor training sessions, consultant-provided auditor training sessions, NERC auditor training modules, NERC ATL training, and ERO auditor workshops. Out of the ten personnel assigned to the Compliance groups, one is a NERC-certified system operator, five are certified information system auditors, and four are registered professional engineers.

SPP RE requires all auditors participating in an audit to undergo a conflict of interest review to identify any potential conflicts of interest between an auditor and the registered entity. Similarly, SPP RE also created a *Contractor Conflict of Interest Audit Procedure* that establishes due diligence requirements for the review of contractor conflicts of interest, validates and documents requirements concerning gaps in contractor employment, and identifies contract consulting history.

Compliance Monitoring Tools and Procedures

SPP RE utilizes numerous tools to facilitate its audits, several of which are highlighted here. SPP RE's audit teams maintain an audit workbook to facilitate evidence request tracking. SPP RE also uses a compliance pre-audit survey, an audit opening and closing presentation template, an operator interview questions template, and a control center checklist template. For CIP audits, SPP RE has implemented the use of a Network Access Policy Tool (NetAPT), which helps auditors with the visualization of the registered entity's network architecture. SPP RE also utilizes a secure file transfer protocol (FTP) server (EFT server) to facilitate the upload and continuous protection of audit evidence.

Quality Assurance

SPP RE's audit process requires all members of the audit team to participate in the review of evidence and SME interviews. The auditors collectively determine a registered entity's compliance with NERC Reliability Standards. All audit findings are reviewed and approved by SPP RE management. After the Compliance group completes a preliminary screen of a potential noncompliance, it enters the potential noncompliance into SPP RE's webCDMS, and notifies the registered entity and NERC of the potential noncompliance. The Compliance group and the Enforcement group then convene a hand-off meeting to discuss the audit findings. If the Enforcement group determines that sufficient evidence exists to support a possible violation, then the Enforcement group sends the registered entity a notice of a possible violation. The Enforcement group conducts a thorough secondary review of all possible violations before final disposition of a registered entity's noncompliance.

Guidance and Training for Industry Stakeholders

The SPP RE Outreach staff works closely with the SPP Regional Transmission Organization (RTO) Outreach and Training staff to coordinate an array of training opportunities for all of the registered entities in the SPP RE footprint. In 2013, SPP RE and SPP RTO provided approximately 25,000 continuing education hours of training to over 1,800 participants.

Additionally, training related to Reliability Standards and compliance activities was provided to over 700 participants on webinars, over 800 participants at workshops and over 1,200 participants on conference calls.[57] All SPP RE workshops and webinars are free and open to the public. SPP RE frequently provides speakers to industry groups such as the Registered Entity SME conferences, executive conferences, and numerous SPP RTO technical groups and committees.

SPP RE continues to add to its library of training videos,[58] publish e-newsletters, and organize lessons learned educational sessions. SPP RE has worked to refine its workshop logistics and presentations, and continues to update the SPP RE webpages with relevant compliance materials. SPP RE's CIP Compliance team made an effort in 2013 to ensure registered entities undergoing a CIP audit understood that, as permitted by GAGAS, the SPP RE audit teams perform outreach activities during the course of the audit. This practice is communicated in the initial audit notice to the registered entity. The ATL periodically communicates with the registered entity during the pre-audit stage to gauge the effectiveness of outreach activities. If the entity is receptive to the outreach, this practice is reiterated during the opening audit presentation.

Maintaining Confidentiality

The SPP RE audit team strictly follows SPP RE's policies and procedures for the custody of confidential audit material. To ensure that the confidentiality of registered entity audit documents is maintained, SPP RE's uses a secure EFT server for storing the registered entity's data during the audit period. To provide yet another layer of protection, SPP RE stores all evidence documents in encrypted form.

Participation in RAI

SPP RE designated two SPP RE auditors as members of the ECEMG MTF that developed the Auditor Manual. In addition, SPP RE designated one SPP RE auditor as a member of the Pilot Evaluation Committee, and two auditors participated as observers during the ReliabilityFirst entity risk assessment pilot for American Electric Power Service Corporation. SPP RE designated three auditors as members of the RSAW Task Force RAI project, where they assisted in the development of new RSAW templates and a Compliance Application Notice conversion process for the new RSAWs. As a member of the Enforcement Functional Group, SPP RE helped draft the *ERO Enterprise Mitigation Plan Guide* and provided input during the development of the NERC Aggregation and Compliance Exception pilot programs. Internally, SPP RE has taken steps to facilitate the Compliance Exception process by adopting changes to its webCDMS and by implementing a triage process for the screening of incoming compliance issues to identify candidates for compliance exception. A SPP RE registered entity is also participating in the CIP Version 5 transition study to identify issues related to the transition from CIP Version 3 to CIP

[57] *See 2013 Compliance Outreach Report* (December 3, 2013), which was discussion item 3H at the December 10, 2013 SPP RTO Board of Directors/Members Committee meeting, available at: http://www.spp.org/publications/BODAGD&BKGD121013.pdf.

[58] SPP RE's video library received the Bronze Quill Award of Merit from the International Associated of Business Communications, Arkansas Chapter (April 2014), available at: http://vimeopro.com/sppcompliance/re.

Version 5. SPP RE CIP Compliance staff is working closely with the registered entity to identify and document transition compliance issues. SPP RE has provided training on the RAI program during its workshops and continues to support RAI by conducting outreach as RAI unfolds.

viii. Texas Reliability Entity, Inc.

Department Structure / Staffing / Conflict of Interest Avoidance

During the assessment period, Texas RE increased its compliance audit staff from 13 to 19 employees, and increased its registration and certification staff from one to two employees plus a supervising director. Audit teams typically consist of the ATL, a dedicated clerk, and team members auditing a subset of requirements included in the audit scope. Many audit team members have over 20 years of industry experience. In 2012, NERC determined that Texas RE needed to increase its CIP audit staffing levels to ensure its continued ability to perform compliance monitoring activities. Since then, Texas RE has increased its dedicated CIP audit staff from four to five employees and cross-trained several Operations and Planning auditors to assist with the workload.

Texas RE auditors participate in various Texas RE internal auditor training sessions, consultant-provided auditor training sessions, NERC auditor training modules, NERC audit team lead training, and ERO auditor workshops. Texas RE has published an audit procedure manual, which contains procedures for confidentiality, training, conflict of interest, and a procedure related to confirmation that the auditor has completed approved training. Texas RE employees must attend ethics and confidentiality training annually and sign agreements confirming that they will disclose any potential conflicts of interest and maintain the confidentiality of registered entity information. During Texas RE's audits, ATLs confirm that confidentiality and ethics agreements have been signed by all audit team members.

Compliance Monitoring Tools and Procedures

Texas RE utilizes a number of tools to execute its audits, several of which are highlighted in this section. Texas RE's compliance management tools, specifically its audit planning publications, audit procedures, audit agenda, and audit team expectations document, serve to organize the responsibilities of each audit team member, provide audit timelines, and include a comprehensive achievement matrix of audit milestones.

Texas RE audit teams utilize NERC's *Actively Monitored List of Reliability Standards* (AML) to identify requirements applicable to the audited entity and to scope audits. They use NERC's RSAWs and Texas RE's CMEP guidelines, which are sometimes used to expand the scope of an audit and include Regional Entity-specific reliability compliance requirements. They also employ a RAT-STATS statistical tool to select testing samples and create a workbook addressing each audited compliance requirement. Texas RE developed a CIP audit checklist used during the walk-though portions of a CIP audit to identify critical assets, critical cyber Assets, access points, and all other cyber assets within the electronic security perimeter. Texas RE's CIP audit checklist tool ensures that all areas of audit concern are addressed. Additional examples of audit tools used during on-site audits and throughout the period leading up to an audit include

email notifications, worksheet summaries, and spreadsheet tables for tracking evidence, and for delivering updates to the registered entity and to audit team members.

One of the notable improvements in the auditing process was Texas RE's implementation of webCDMS software in 2012, which allowed it to eliminate the manual tracking and reporting processes and synchronize document submission with NERC's database. Texas RE has also updated its audit desk procedures to ensure that auditors are using uniform processes to determine the scope of audits, notify entities of audits, document audit findings, and ensure that draft audit findings are reviewed by management before being sent to registered entities.

Quality Assurance

Texas RE's audits are led by the Texas RE ATLs, who coordinate audit activities and communicate issues pertinent to the performance of the team's work. These teams meet to review the progress of the audit and at the close of the day, the ATL meets with the entity to review audit progress and clarify the status of outstanding data requests and delivery expectations. All audit documentation is saved on a secure server and is subject to a formal document retention schedule. On the last day of the on-site portion of an audit, the audit team provides a summary briefing to the registered entity, describing any possible issues the team identified. The audit manager also reviews the draft audit findings before providing them to the registered entity for comment. At the conclusion of the audit, the audited entity is provided a questionnaire asking for comments on how the audit process could be improved. Questionnaires are reviewed by Texas RE management and lessons learned from the feedback are shared with audit staff.

Guidance and Training for Industry Stakeholders

Since 2009, Texas RE increased its training resources for its Training, Education, and Operator Certification program, which provides continuing education hours through the NERC Continuing Education program. Texas RE dedicated 0.6 FTE to its Training, Education, and Operator Certification program in 2009.[59] Last year, Texas RE delivered its 2013 training program through 1.75 FTEs.[60] Texas RE has an external relations manager and a communications and external relations coordinator who coordinate scheduling of training and development of training materials; however, most training is conducted by auditors from Texas RE's Compliance department. In an effort to improve outreach and training for smaller registered entities with insufficient resources to participate in-person at compliance workshops, Texas RE offers webinar capabilities. On occasion, Texas RE conducts smaller, in-person training presentations for stakeholders unable to attend annual workshops, but that are experiencing compliance issues identified during audits.

Texas RE offers the following additional sources of guidance and training to industry members:

(1) A website with information about Texas RE and its activities, including links to CMEP information and enforcement information;

[59] 2010 Business Plan and Budget, Texas Regional Entity, Inc., June 15, 2009.

[60] 2013 Business Plan and Budget, Texas Regional Entity, Inc., June 27, 2012.

(2) A listserv for distribution of announcements;

(3) Monthly regional stakeholder CIP working group meetings which must be attended in person due to the sensitive nature of the shared information;

(4) "Talk with Texas RE" webinar meetings, which facilitate open discussions of reliability and compliance issues with stakeholders;

(5) Teleconference meetings of the NERC Standards Review Subcommittee (a subcommittee of the Texas RE Reliability Standards Committee) approximately every two weeks, which serve as a forum for discussion of NERC Reliability Standards under development; and

(6) The *Texas REview* a monthly newsletter which includes topics related to NERC compliance (including reminders about compliance deadlines), enforcement, and lessons learned.

Maintaining Confidentiality

Texas RE requires all employees to attend ethics and confidentiality training annually and to sign an agreement requiring them to keep registered entity information confidential. Texas RE also has procedures requiring its employees to keep all compliance information confidential. Texas RE has a hotline and website where anyone can file a complaint regarding a registered entity's compliance with NERC Reliability Standards, and the complainant may remain anonymous. In addition, Texas RE safeguards the confidentiality of registered entity data by using a secure compliance data portal (WebCDMS), using a secure FTP site for data submission, and maintaining data server security through the use of firewalls, system monitoring and penetration testing. All Texas RE staff are also required to complete annual IT and physical security training.

Participation in RAI

Texas RE has been working with NERC and the other Regional Entities to implement RAI. In 2013, Texas RE worked with NERC and the other Regional Entities to develop the *Compliance Auditor Checklist*, and provided significant support toward the development of the *Compliance Auditor Handbook*, as found in the Auditor Manual. In 2014, Texas RE helped evaluate the effectiveness of the RAI pilot programs conducted in other Regional Entities. Texas RE is working to encourage collaboration, emphasize consistency and align proven processes. Texas RE co-hosted an RAI and Internal Controls workshop in February 2014, and a follow-up meeting with Texas RE in March 2014 to answer questions received during and after the workshop.

ix. <u>Western Electricity Coordinating Council</u>

Department Structure / Staffing / Conflict of Interest Avoidance

FERC issued its final orders on February 12, 2014 approving the bifurcation of WECC. Bifurcation resulted in a more focused reliability assurance mission for WECC and Peak

Reliability (Peak) (the new company formed to be the reliability coordinator for the Western Interconnection). WECC will continue as the Regional Entity for the Western Interconnection and focus on RAI activities as it assumes the role of compliance enforcement authority for Peak along with all other registered entities in WECC's footprint. That role includes monitoring and enforcing compliance with mandatory Reliability Standards, as well as having a leadership role in reliability planning and performance assessment of the BPS in the Western Interconnection.

Since January 2009, the Compliance staffing at WECC has increased from 31 to 53 employees, not counting contractors. Staffing increases have occurred throughout Compliance to satisfy the CMEP requirements associated with the increased number of registered entities and registered functions, which to date respectively total 510 and 1,353 respectively, up from the 466 and 1,248 reported in 2009. WECC's number of scheduled audits has almost doubled from 98 in 2009 to 171 in 2013.

WECC's Program Administration department was established in 2008 and restructured in 2012 to ensure the accurate, efficient, and timely exchange of compliance information between registered entities, WECC, and NERC. The department supervises the services and support used by the registered entities and WECC employees to interact with such systems as webCDMS and the WECC EFT server. Staff in this department are currently comprised of one manager and six employees.

Since 2009, the WECC Compliance department has put in place a rigorous training and development program. Like other Regional Entities, WECC struggled initially to fill both Operations and Planning and CIP auditor positions. A recruitment and development plan to recruit, graft and grow expertise included mentoring, cross-training and implementing development milestones programs. WECC also benefits from using industry SMEs as contractors for its audits. These contractors possess operations, planning, and power system knowledge as well as skills and abilities that complement that of WECC's audit staff to fill gaps where specific deficiencies may exist. WECC partners these contractors with less experienced auditors at each audit to provide detailed and in-depth on-the-job training, and educational experiences regarding specific Reliability Standards and requirements. Additionally, all CIP auditors hold at least one relevant certification (e.g. CISA, CISSP).

Audit teams regularly participate in cross-training within their own team through constant rotation in ATL responsibility. In addition, auditors in teams of two are frequently assigned different Reliability Standards and requirements to audit, depending on an audit's scope. This approach provides varied and valuable training opportunities to increase auditor knowledge of and expertise on multiple Reliability Standards. Operations and Planning and CIP SMEs from both Compliance and Enforcement are assigned to participate with auditors on the audit team for at least two audits per year as part of the cross-training effort. This results in a greater understanding of the WECC audit approach by the Enforcement team SMEs, while providing much needed "bench strength" to the audit teams and their ability to satisfy audit staffing requirements. Both Operations and Planning and CIP audit team members in WECC have participated in various WECC internal auditor training sessions, consultant-provided auditor training sessions, NERC auditor training modules, NERC ATL training, and ERO auditor workshops.

WECC conducts conflict of interest checks for its auditors and contractors. WECC's compliance program coordinators (CPCs) are responsible for distributing and collecting these forms. These forms are reviewed by the audit managers and the managing director of compliance at the beginning of every year. In August 2013, WECC included the additional step of having the CPC and the ATL review these forms in connection with every audit, as part of WECC's preliminary audit preparation. This will add an extra layer of review to ensure that the conflict of interest forms are complete and accurate. WECC has also codified these existing and new processes in the CPC informal process manual as part of a basic checklist for audits.

Compliance Monitoring Tools and Procedures

WECC utilizes a number of tools to execute its audits, several of which are highlighted in this section. WECC performs audits in the timeframes anticipated by the CMEP. WECC's Operations and Planning audit teams rely primarily on RSAWs to record audit findings, interview notes, evidence and samples. While WECC did not initially follow GAGAS audit procedures to conduct audits, particularly in the areas of planning, scope, evidence, testing, sampling and documentation, WECC later adopted various professional resources such as the GAGAS, NERC auditor training guidance and other best practices. WECC leverages the *Compliance Auditor Handbook* and associated *Compliance Auditor Checklist* (as found in the Auditor Manual) in addition to the WECC CIP standard operating procedures for documented audit procedures.

The audit teams use a number of secure tools, leveraged by PGP encryption methodologies, to manage the administrative and logistical support for audits. The primary tool used by the audit team is an Audit Remote File server used to expedite the availability of electronic information to auditors during a remote audit. This tool works in conjunction with WECC's EFT server and the WECC internal Sharedrive. When an entity uploads audit evidence to the EFT server, a WECC employee is notified of the change and moves the files to the correct location within the WECC internal Sharedrive. The software then automatically synchronizes the files on WECC's internal Sharedrive with the files on the Audit Remote File server. This system allows all users to access the exact same information from different connection points.

In 2013, WECC launched the Audit Tracking System (ATS) to help manage the tracking, and the timely completion and filing, of audits. The software minimizes rework, helps prevent errors in documentation, and ensures that all related tasks are completed in a timely manner. There are four pieces to the new ATS: audit scheduling, audit metrics, audit library, and audit report task list. Another feature of the ATS is that metrics are now readily and easily available to managers through the system. The system uses an Audit Library to minimize document duplication by tracking the version history on each file and eliminating multiple copies of the same report. Finally the system incorporates an audit task list that reduces manual oversight by electronically tracking task assignments, completions, and notifications.

WECC has been able to greatly reduce the amount of human and budget resources required for compliance support activities. Actual expenditures in 2010 exceeded $1.9 million; in 2012 that number dropped to less than $1.1 million. Starting in 2012, WECC began to concentrate on operational efficiencies that could simplify the growing complexity of managing compliance data and transactions. The single greatest change in that process was upgrading the compliance transaction platform from the WECC Compliance Portal to webCDMS. The new system brought

drastic reductions in the amount of time WECC employees spent on sending data requests, sending reminder notices to registered entities, summarizing compliance data, and transmitting compliance data to NERC.

WECC created an audit report tool that provides readable access to critical data, drives visibility across audit team members and management, and improves the efficiency of the audit report processes. This project streamlines the audit schedule activities and audit report process for audit management, ATLs, and CPCs. The solution minimizes rework, helps prevent errors in documentation, and ensures that all related tasks are completed in a timely manner. This tool also enables management and audit team members to understand workload and prioritize items. Prior to the launch of this tool, significant time and effort was spent on manual oversight.

WECC also created the Compliance Standards Index (CSI). The CSI works by drawing on a number of data sources to place relevant information about Reliability Standards in a single view. The CSI queries NERC's Reliability Standards database, which is the repository for the most current and updated information on Reliability Standards. The system then combines this data with related information such as a link to the WECC RSAW and the WECC AML. Altogether, the CSI allows users to get a more complete view of applicable Reliability Standards.

Quality Assurance

Audit findings are reviewed by the entire audit team, including the ATL, before a possible violation is identified. All possible violations are then reviewed by an Enforcement SME for confirmation. All audit reports and findings are reviewed and approved by senior Compliance management before being sent to the registered entity and NERC. Post audit feedback forms are completed by audited registered entities and reviewed by the ATL, the audit team and senior Compliance management before being discussed in auditor staff meetings. Lessons learned are discussed on an informal basis in both the Operations and Planning and CIP audit team meetings. CIP audit teams document lessons learned and store them on an internal secure WECC server for future auditor review and reference. Audit documents, including evidence, data and reports, are stored on a dedicated drive and SharePoint and archived according to the WECC formal data retention policy of five years.

Guidance and Training for Industry Stakeholders

Beginning in 2009, WECC has offered annual training sessions and workshops for operators, schedulers, and dispatchers. During the assessment period, WECC decreased its training resources for its Training, Education, and Operator Certification program, which provides continuing education hours through the NERC Continuing Education program. WECC dedicated 3.5 FTE to its Training, Education, and Operator Certification program in 2009.[61] Last year, WECC delivered its 2013 training program through 1.5 FTEs.[62]

WECC formalized a compliance outreach program in the fall of 2008 with the hiring of a designated individual to act as a liaison with the registered entities and to coordinate various

[61] 2009 Business Plan and Budget, Western Electricity Coordinating Council, July 9, 2008.

[62] 2013 Business Plan and Budget, Western Electricity Coordinating Council, June 25, 2012.

compliance outreach activities. The director of compliance outreach reported directly to the WECC CEO at that time. This reporting structure assured the separation of Outreach and Compliance Audit and Enforcement. In January 2011, the scope of this position expanded to include outreach to other interested stakeholders. The current position is managing director of stakeholder outreach which reported to the vice president of communications and external affairs during the assessment period and now reports to the vice president and chief administrative officer. This individual is responsible for the coordination of all compliance outreach activities as well as ad hoc outreach for other WECC areas, as appropriate (e.g. BES definitional process).

Below are examples of WECC outreach to registered entities:

(1) WECC hosts three Compliance User Group (CUG)/Critical Infrastructure Protection User Group (CIPUG) meetings annually. These meetings, held over three days, allow time for industry-only Western Interconnection Forum (WICF) sessions. Attendance records (kept electronically since 2011) indicate that participation continues to increase yearly while satisfaction surveys show favorable responses. The CUG/CIPUG agendas cover a wide range of topics including management updates, regulatory actions, industry trends, new Reliability Standards, audit approaches and best user practices. Registration for 2011 through 2013 was 5,717.

(2) WECC hosts open webinars on the third Thursday of most months. These sessions are used to provide time-sensitive updates on topics and issues that arise between CUG meetings and reminders of upcoming events and deadlines. Participation is also very good in this Outreach program with 150 to 250 active ports for each webinar. WECC added real time video streaming capability in 2013.

(3) Starting in January 2011, enforcement SMEs started conducting outreach events to educate registered entities about best practices in submitting information to WECC, and mitigation and prevention of violations. Some of the specific outreach activities include:

(a) Eight Steps for Prevention and Mitigation – The goal of this outreach presentation was to share best practices in creating effective mitigation plans. It provided registered entities eight important elements to consider while creating a mitigation plan for a violation.

(b) Detection and Future Prevention – The goal of this outreach program was to highlight the importance of determining the root cause and implementing strong detection and preventative measures to reduce the likelihood for future recurrence of violations and security issues.

(c) Reliability Standard Specific Outreach – Enforcement SMEs have conducted various events to discuss the audit approach, root cause analysis and effective mitigation solutions for most commonly violated Reliability Standards in the WECC region. Some of these Reliability Standards include: PRC-005; PER-002 and PER-003; PRC-023; VAR-002; and CIP-007.

(4) The WICF is run by and on behalf of entities subject to WECC and NERC compliance requirements. The purpose of WICF is to provide registered functional entities within the Western Interconnection a venue to share knowledge and lessons learned regarding compliance matters, and to collectively develop best practices.

(5) CIP 101 is a two-day class held generally in WECC's Salt Lake City, UT meeting space and is taught by WECC cybersecurity auditors. This class has been offered three times and has sold out each time. Agendas include comprehensive discussions of CIP Reliability Standards, audit approaches, best evidence and interactive work between participants and the WECC auditors.

(6) A "Compliance 101 Webinar" which is a 90-minute session offering an overview of the development of the mandatory compliance program and its major parts. WECC offers this webinar just before each CUG/CIPUG meeting to aid those new to their compliance duties or who may just want refresher training.

(7) WECC hosts compliance systems (EFT/webCDMS) training and webinars providing registered entities with an opportunity to learn about the improvements to these electronic systems.

Maintaining Confidentiality

WECC employs a number of security measures to protect confidential compliance information. WECC laptops with access to confidential information have encrypted hard drives, minimizing the risk of that information being disclosed in the event of a lost or stolen laptop. WECC requires employees to change the passwords on their laptops every 90 days. WECC's offices have physical security measures including badge readers, access badges for all employees, and video cameras which cover the building entrances and exits. There is also an on-site security guard for the building during business hours. Visitors must be escorted by WECC employees in nonpublic areas of the offices. Additionally, WECC uses two secure portals/repositories for registered entity submittals: webCDMS and the EFT server.

Participation in RAI

As part of the RAI, WECC volunteered for the ECEMG MTF that created the Auditor Manual. WECC has also provided its internal training materials to NERC, at its request.

WECC completed its first RAI pilot in 2013 with limited scope and time. WECC provided recommendations to the entity to further consolidate its internal controls. Based on the results, WECC customized the self-certification requirements for the entity. WECC used the entity's feedback to improve its internal controls evaluation process. In May 2014, WECC completed its second RAI pilot. WECC highlighted best practices and recommendations to the entity. A WECC audit team used the results of the controls evaluation to exclude certain requirements from the entity's compliance audit. The entity was also selected for the Compliance Exception pilot. The

entity provided helpful and positive feedback which WECC has used to improve the evaluation process. Currently, the third RAI pilot is in progress.

C. Compliance Investigations

The Compliance Investigations group provides quality assurance of the Regional Entities' compliance evaluations of industry compliance assessments from events that have occurred in their footprints. The Compliance Investigation group's process articulates NERC's technical investigations staff review and facilitates a compliance evaluation of BPS events as they relate to the entities involved in the event. It also outlines subsequent compliance responsibilities under the NERC Reliability Standards.

NERC's Compliance Investigations group works closely with Regional Entity compliance staff to review significant BPS disturbances. These reviews include evaluation of events from a compliance perspective, which includes a review of possible gaps in existing NERC Reliability Standards. During such events, registered entities are encouraged to conduct a compliance self-assessment and submit these assessments to the relevant Regional Entity for review. The registered entity is encouraged to self-report possible violations it identifies during this self-analysis. In its oversight role, NERC reviews and analyzes each compliance self-assessment to ensure consistency and to initiate lessons learned or compliance monitoring follow-up activities.

At the beginning of the assessment period, compliance investigations and event-driven compliance evaluations proved difficult to complete at the Regional Entity level, in part due to the need for more resources. NERC found that the Regional Entities had difficulty determining which BPS events required a more detailed review and in understanding what was required of them in compliance investigations. As further detailed in the *Overview of NERC Activities and Accomplishments in the Five-Year Period*, these issues were addressed through several initiatives including the creation of the ERO Event Analysis program and NERC's development of a compliance investigations leaders training class for NERC and Regional Entity staff compliance investigators. The compliance investigations leaders training material is continuously reviewed and improved based on feedback from compliance investigation experiences and changes to GAGAS, CMEP, and the NERC ROP. As a result of these efforts, the Compliance Investigations group regularly processes over 30 events per year and works with the Events Analysis group to publish relevant NERC alerts.

In addition, the Compliance Investigations group handles all complaints reported to NERC regarding alleged violations of NERC's Reliability Standards. These matters are reported through the compliance hotline or by voice messaging. Between March 2009 and December 2012, NERC in collaboration with the Regional Entities, received, processed and closed all 70 complaints that were received by the ERO.

D. Compliance Enforcement

1. Performance of the ERO Enterprise

a. Overview

During the assessment period, the Regional Entities made remarkable progress in establishing mature, effective enforcement programs consistent with their obligations under the RDAs and the NERC ROP. The RDAs delegate authority over enforcement of compliance with Reliability Standards. The RDAs provide that NERC shall review the Regional Entities' CMEP as often as NERC deems necessary to ensure that: (1) the Regional Entity's program meets all applicable legal requirements; (2) the actual practices of the Regional Entity reflect the requirements; and (3) the program promotes consistent interpretations across North America of Reliability Standards and comparable levels of sanctions and penalties for violations of Reliability Standards constituting comparable levels of threat to the reliability of the BPS.[63] The NERC ROP require the Regional Entities to make initial determinations of compliance or noncompliance and recommend penalties where authorized,[64] apply penalties and sanctions that bear a reasonable relation to the seriousness of a violation and that follow the directives, principles, and processes set forth in NERC's *Sanction Guidelines*,[65] regularly report on the status of the review and assessment of violations of Reliability Standards as well as associated mitigation plan information,[66] and obtain sufficient resources to meet their delegated obligations, including maintaining sufficient staffing.[67] NERC, as part of its oversight role, regularly reviews Regional Entity enforcement activities to ensure that these obligations are being satisfied and to drive the implementation of best practices in enforcement activities throughout the ERO Enterprise. NERC's oversight activities provide an ongoing view of the Regional Entities' effectiveness in executing their compliance enforcement responsibilities.

At the time of the *Three-Year ERO Performance Assessment Report* (mid-2009), the NERC Reliability Standards had been mandatory and enforceable for just over two years. Early in the implementation of the uniform CMEP, the Regional Entities successfully identified some 2,000 violations from the over 2,700 reported possible violations.[68] Additionally, the Regional Entities addressed a large number of self-reported Reliability Standard violations[69] from the period before

[63] Section 6 of each RDA contains the provisions relating to delegation of compliance monitoring and enforcement authority.

[64] NERC ROP §402 (NERC Oversight of the Regional Entity Compliance Monitoring and Enforcement Programs).

[65] NERC ROP §401 (Scope of the NERC Compliance Monitoring and Enforcement Program); *Sanction Guidelines* are Appendix 4B to the ROP.

[66] *See* NERC CMEP, NERC ROP Appendix 4C, at §6.0 (Mitigation of Violations of Reliability Standards).

[67] NERC ROP §403 (Required Attributes of Regional Entity Compliance Monitoring and Enforcement Programs).

[68] *Three-Year ERO Performance Assessment Report*, Attachment 3 at 10-11.

[69] Unless otherwise indicated, "violation" refers to any report of noncompliance submitted to a Regional Entity, regardless of its status as a possible, alleged, or confirmed violation or whether the noncompliance was or will be processed as a "remediated issue" through the Find, Fix, Track and Report (FFT) track.

the Reliability Standards became mandatory and enforceable.[70] NERC recognized in the three-year performance assessment the success of the Regional Entities in the cataloging, processing, and tracking of each violation and the completion of the associated mitigation plans. NERC also recognized that substantial work remained to be done to complete the transition to a more mature enforcement program. In the three-year performance assessment, NERC noted several areas of improvement for the Regional Entities, including increasing the speed of processing violations (and associated mitigation plans) and improving upon the thoroughness and accuracy of the information provided to support each Notice of Confirmed Violation (NOCV) or settlement agreement submitted to NERC for review.[71]

During the current assessment period,[72] NERC and the Regional Entities worked to develop more mature enforcement processes for the ERO Enterprise. NERC and the Regional Entities collaboratively implemented streamlined enforcement processing mechanisms, such as the Spreadsheet Notice of Penalty (SNOP) and FFT enforcement mechanism.[73] NERC and the Regional Entities also worked together to design and build a system for the collection, management, and exchange of compliance-related information between NERC and the Regional Entities. The Regional Entities implemented compliance data systems that interface with NERC's Compliance Reporting, Analysis, and Tracking System (CRATS). These complementary systems are the webCDMS, which is used by MRO, ReliabilityFirst, SPP RE, Texas RE, and WECC, and the CITS, which is used by FRCC, NPCC, and SERC. These systems enable enforcement processing efficiencies and facilitate consistent tracking of violation status across the ERO Enterprise. These systems are continuously evaluated and improved.

For several years, NERC has closely tracked various aspects regarding the overall performance of the ERO Enterprise as it relates to enforcement activities. Beginning in 2013, NERC and the Regional Entities developed and implemented a series of metrics to track and evaluate the performance of the ERO Enterprise and of each Regional Entity. These metrics allow NERC to analyze trends and identify areas where further improvements may be achieved. To facilitate consistent application of these metrics, NERC and the Regional Entities agreed to a set of business rules to govern submission of data to the complementary compliance data systems. For 2014 and beyond, NERC and the Regional Entities have agreed to use some of these metrics to measure achievement of the goals of the *ERO Enterprise Strategic Plan*.[74] Although these metrics were not in place during the entire assessment period, they provide insight into the current status of enforcement processing in the ERO Enterprise, and therefore are used in this evaluation.

NERC recognizes the substantial progress each Regional Entity has made in addressing the enforcement-related issues raised in the three-year performance assessment. NERC also

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[70] *Three-Year ERO Performance Assessment Report*, Attachment 3 at 12.

[71] *Three Year ERO Performance Assessment Report*, Attachment 3 at 11-12.

[72] For purposes of evaluating the Regional Entities' activities, NERC has used a five-year period of January 1, 2009 to December 31, 2013.

[73] The SNOP and FFT enforcement mechanisms are described in §II.D.b.iv below.

[74] *See ERO Enterprise Strategic Plan 2014-2017*, available at: http://www.nerc.com/gov/Annual%20Reports/ERO%20Enterprise%20Strategic%20Plan%202014-2017%20and%20Performance%20Metrics.pdf.

recognizes the progress each Regional Entity has made in improving consistency and transparency in enforcement-related processes. However, and as explained more fully below, NERC has identified the need for additional improvements with respect to enforcement processing and the Regional Entities' implementation of certain aspects of the CMEP.

This assessment of the enforcement activities of the Regional Entities begins with a discussion of the collective accomplishments of the ERO Enterprise with respect to enforcement processing and a discussion of general recommendations for areas of improvement. Topics that will be covered include ensuring the timely processing and mitigation of older violations, ensuring the quality of data in the compliance data tracking systems, ensuring the quality of submitted information in settlement agreements and NOCV, and NERC's oversight of the performance of the Regional Entities with respect to certain areas of the CMEP. The analysis of the collective accomplishments of the Regional Entities in enforcement is followed by in-depth analysis of the performance of each Regional Entity in executing its compliance enforcement responsibilities.

b. Improvements in Enforcement Processing, 2009-2013

In 2009, at the time of the three-year performance assessment, the Regional Entities had collectively accumulated what was described as a substantial backlog of cases. Of the total 1,926 violations identified by the Regional Entities, only 475 violations had been filed with NERC for its review and for Board of Trustees Compliance Committee (BOTCC) approval as of May 31, 2009. Roughly 75 percent of all violations that had been identified remained to be processed by Regional Entity staff.[75]

During the current assessment period, the Regional Entities have made substantial progress in reducing the number of open violations, despite substantial increases in the numbers of new violations during the assessment period.

i. The Composition of the ERO Enterprise Caseload

As shown by the table below, 10,163 violations were reported to NERC by the Regional Entities during the current assessment period. The Regional Entities reported a significant increase in the number of violations from 2010 through 2012, in large part due to the implementation and enforcement of the CIP Reliability Standards:

[75] *Three-Year ERO Performance Assessment Report*, Attachment 3 at 11.

Violations for all Regional Entities 2009-2013 by Year Reported to NERC
U.S. Violations Only[76]

Regional Entity	2009	2010	2011	2012	2013	Grand Total
FRCC[77]	188	109	141	69	61	568
MRO	60	103	196	166	139	664
NPCC	43	99	130	213	66	551
RFC	123	469	565	505	240	1902
SERC	187	312	309	300	285	1393
SPP RE	132	254	291	173	191	1041
TRE	14	51	430	197	169	861
WECC	571	550	807	818	437	3183
Grand Total	**1318**	**1947**	**2869**	**2441**	**1588**	**10163**

The drop in violations from 2012 to 2013 is attributable to a number of factors.[78] Since the Reliability Standards became mandatory and enforceable, most registered entities have completed at least one full audit cycle and in some instances more than one audit cycle. A number of registered entities have responded to their past compliance audits by improving their management practices, thus decreasing the likelihood of the Regional Entity discovering new violations in recent compliance audits. In addition, the Regional Entities have conducted significant and varied outreach activities. These efforts have included Operations and Planning standards workshops, CIP standards workshops, and training to enhance their registered entities' understanding of the Reliability Standards. Registered entities with better knowledge of the Reliability Standards have improved their compliance cultures, and therefore are less likely to have violated Reliability Standards. The drop in violations is also attributable to an enhancement in the preliminary screening processes as of December 2012. Specifically, this enhancement reduced the likelihood that new potential noncompliance issues were duplicates of issues already being processed.

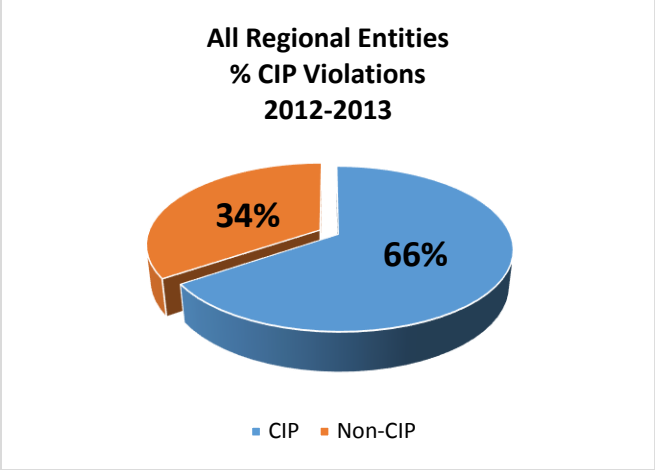
[76] This table reflects all U.S. violations that were submitted via the complementary compliance data systems to NERC's centralized database (CRATS) in 2009, 2010, 2011, 2012, and 2013. This table includes all violations, whether they were later dismissed or were held due to a court, regulator, or appeal. For some violations, the year the violation was discovered and the year the violation was first reported to NERC's centralized database are different. For example, a violation first discovered during an audit in late 2012 may not have been reported to NERC's centralized database until early 2013. Therefore, the total number of violations for a particular Regional Entity or a particular year may vary depending on whether violations are reported by discovery year or by year submitted to NERC's centralized database. To clarify, these differences, where they appear, are attributable to a difference in presentation and reporting rather than an underlying difference in the number of overall violations. For consistency throughout this analysis, the year the violation was first reported to NERC's centralized database is used in this five-year performance assessment unless otherwise specified.

[77] In the JRESA, FRCC reported violations by the year the violations were discovered, rather than the year the violations were submitted to NERC's centralized database. *See* JRESA at 41. As noted above, the differences between the numbers reported by NERC in the table above and the numbers reported by FRCC in the JRESA are attributable to the difference in presentation, rather than an underlying difference in the overall number of violations.

[78] This drop in violations appears whether the number of violations is presented by discovery year or by year reported to NERC's centralized database. When calculated by year of discovery, there was a 12% decline in violations from 2011 to 2012, and a 30% decline in violations from 2012 to 2013.

However, despite the decrease in the overall number of potential noncompliance issues identified, the composition of the ERO Enterprise caseload remained fairly consistent from 2012 to 2013. Since 2010, violations of the CIP Reliability Standards have comprised the majority of violations in each year, with the overall proportion of CIP violations increasing somewhat year over year. CIP violations comprised 66% of the total violations submitted to NERC's centralized database from January 1, 2012 through December 31, 2013.

Type of Violations Reported to NERC by all Regional Entities, 2012-2013

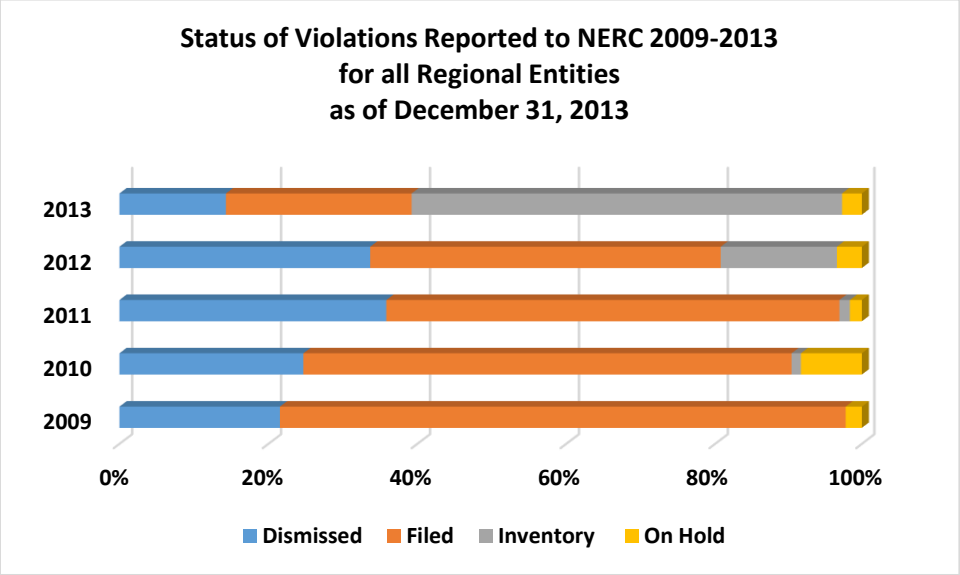


The top five most violated Reliability Standards were CIP-004, CIP-005, CIP-006, CIP-007, and PRC-005. The most violated Reliability Standards were generally consistent across the Regional Entities.

Despite the influx of CIP violations during the assessment period, the Regional Entities actively worked to reduce the number of open violations in their caseloads. As of December 31, 2013, the Regional Entities had processed 100% of the violations available to be processed that were reported to NERC in 2009; nearly 99% of the violations available to be processed that were reported to NERC in 2010 and 2011; and 84% of the violations that were reported to NERC in 2012.[79] Violations reported to NERC in 2012 and 2013 comprised over 95% of the total 1,375 violations available for processing as of December 31, 2013.

[79] NERC recognizes that the Regional Entities are not able to process certain violations because the violations are being held by or due to an appeal, a court, or a regulator. NERC refers to these violations as being "on hold." In evaluating the performance of the Regional Entities with respect to violation processing, NERC excludes any "on hold" violations.

Status of Violations Reported to NERC 2009-2013 for all Regional Entities



As of December 31, 2013, the majority of violations in the ERO Enterprise inventory (67%) consisted of violations reported to NERC in 2013.[80] In addition, during 2013, the Regional Entities processed approximately 39% of the new violations reported to NERC in 2013. By reducing the number of older violations, the Regional Entities are moving toward a caseload consisting primarily of newer violations. The efforts of the Regional Entities to process older violations in their inventories, which has resulted in the reduction in caseload, are described more fully in §II.D.1.b.iii below, Efforts to Reduce Older Caseload.

ii. The Caseload Index

As noted above, NERC and the Regional Entities developed a series of enforcement processing metrics to aid in monitoring and improving the efficiency of enforcement processing throughout the ERO Enterprise. The Caseload Index is one of these metrics. It is used to facilitate planning, coordination, and collaboration between NERC and the Regional Entities.

The Caseload Index is a snapshot of current enforcement processing rates. It measures the amount of time, in months, that it will take the ERO Enterprise (or an individual Regional Entity) to eliminate the existing inventory, assuming no new violations are received. This calculation is based on the processing rate of the previous 12 months. For example, if the Caseload Index is calculated on December 31, 2013, the time to process existing inventory will be based on the processing rate from January 2013 to December 2013. A lower Caseload Index indicates that the ERO Enterprise will need fewer months to clear out its existing inventory of violations available to be processed, based on the processing rate of the previous 12 months. A higher Caseload Index indicates that the ERO Enterprise (or individual Regional Entity) would need more months to clear

[80] The violations in "inventory" refers to identified violations that have not completed processing and are not "on hold."

out its existing inventory. The Caseload Index may fluctuate from month to month as violations are received and processed, but is helpful for evaluating performance over time.

NERC first began monitoring the Caseload Index in 2011 and has targeted achieving a lower average ERO Enterprise Caseload Index in each successive year. As of July 1, 2011, the average ERO Enterprise Caseload Index was 35 months. NERC set a goal to achieve an average ERO Enterprise Caseload Index of 24 months by the end of the year. By the end of 2011, the average ERO Enterprise Caseload Index was 24 months, meeting the goal and marking a substantial improvement from just six months earlier.

In 2012, the calculation of the Caseload Index was refined to account for matters processed through dismissal. The average ERO Enterprise Caseload Index as of December 31, 2012 was 13.3 months.[81] For 2013, NERC sought to achieve an average ERO Enterprise Caseload Index of under 10 months. Throughout 2013, the Caseload Index decreased fairly steadily to approximately 6.5 months at the end of the year.

The overall decrease in the ERO Enterprise average Caseload Index since 2011 reflects the substantial work by NERC and the Regional Entities to implement processing efficiencies and reduce the number of older open violations. These efforts are described more fully in the next section.

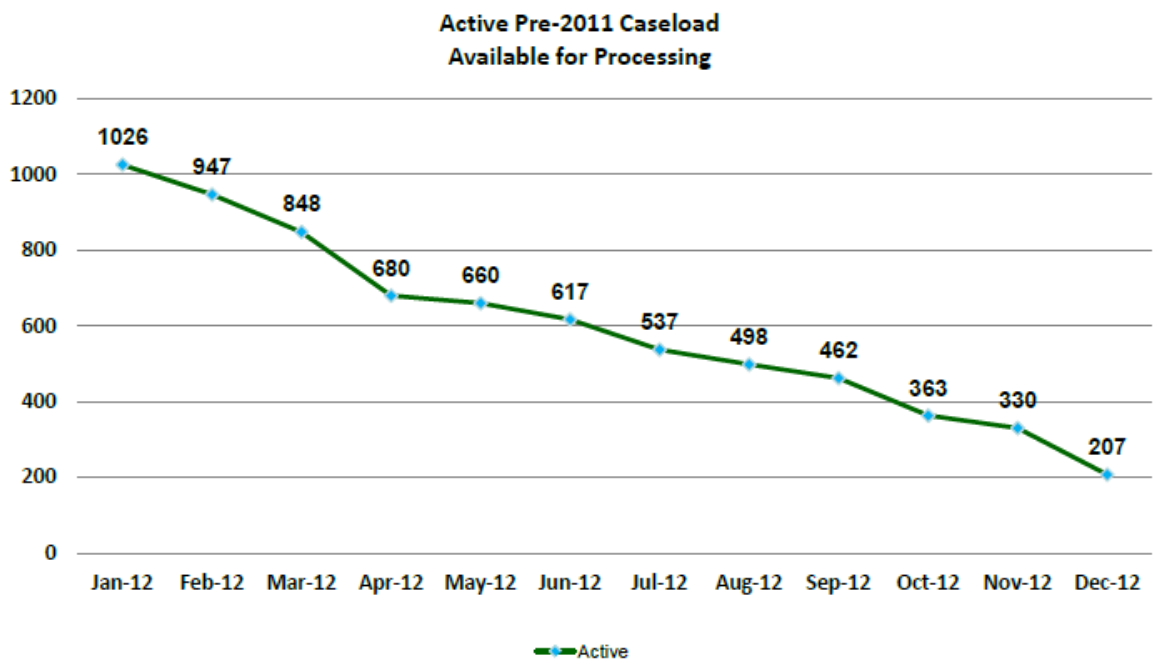
iii. Efforts to Reduce Older Caseload

In the Three-Year Performance Assessment, NERC noted that the Regional Entities needed to make substantial improvements in the processing of violations. NERC noted that the Regional Entities needed to reduce what NERC termed a "backlog" of aging violations. During the current assessment period, the Regional Entities made substantial progress in this regard. Whereas the Regional Entities had processed only about 25% of then-existing violations at the time of the Three-Year Performance Assessment in 2009, the Regional Entities have collectively processed more than 86% of violations reported to NERC from 2009 to 2013. The efforts of the Regional Entities to reduce the number of aging violations have been commendable. These efforts reflect the growth and maturity of enforcement staff across the ERO Enterprise and demonstrate the willingness of the Regional Entities to participate in the development and execution of common goals under NERC leadership and oversight.

In 2012, 2013, and 2014, NERC established corporate goals to reduce the number of older violations remaining to be processed. Working with NERC, the Regional Entities invested significant time and resources in processing the older violations. As a result, the ERO Enterprise reduced the number of open, older violations substantially. For example, during 2012, NERC and the Regional Entities successfully worked to reduce the number of open violations dating from before 2011 (excluding on-hold violations) by 80%, as shown below:

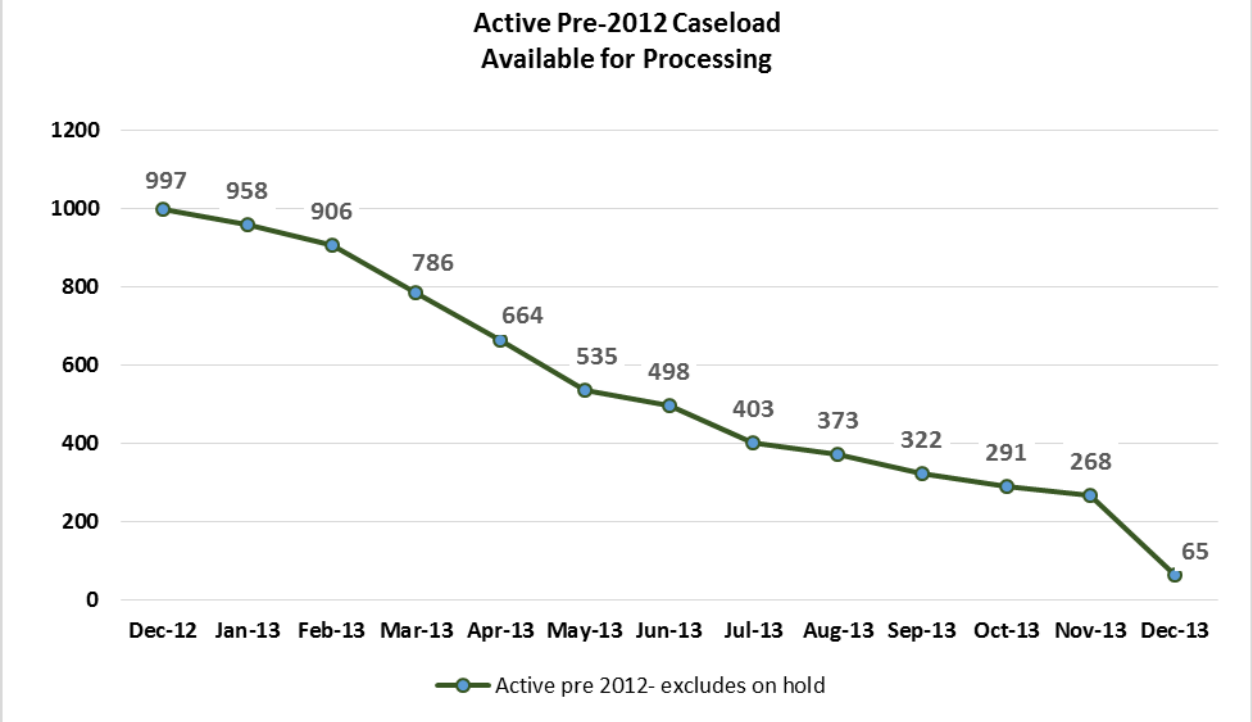
[81] For 2012, NERC established a corporate goal of 12 months for the ERO Enterprise average, with the threshold set at 19 months.

ERO Enterprise Caseload Consisting of Violations Discovered Before 2011 (excluding on hold violations), by Month in 2012



During 2013, the Regional Entities built on the successes of 2012. By December 31, 2013, NERC and the Regional Entities reduced the number of pre-2012 violations (excluding on hold violations) by 93%, as demonstrated below:

ERO Enterprise Caseload Consisting of Violations Discovered Before 2012 (excluding on hold violations), by Month in 2013



Only 65 violations discovered before 2012 remained to be processed as of December 31, 2013, representing less than one percent of total violations discovered from 2007 through 2011 and less than five percent of the violations available to be processed as of December 31, 2013. By working to reduce the number of aging violations while improving the processing speed for newer violations, NERC and the Regional Entities have reduced the average violation age from 11.86 months in 2012 to 11.2 months in 2013 – an improvement of nearly six percent.

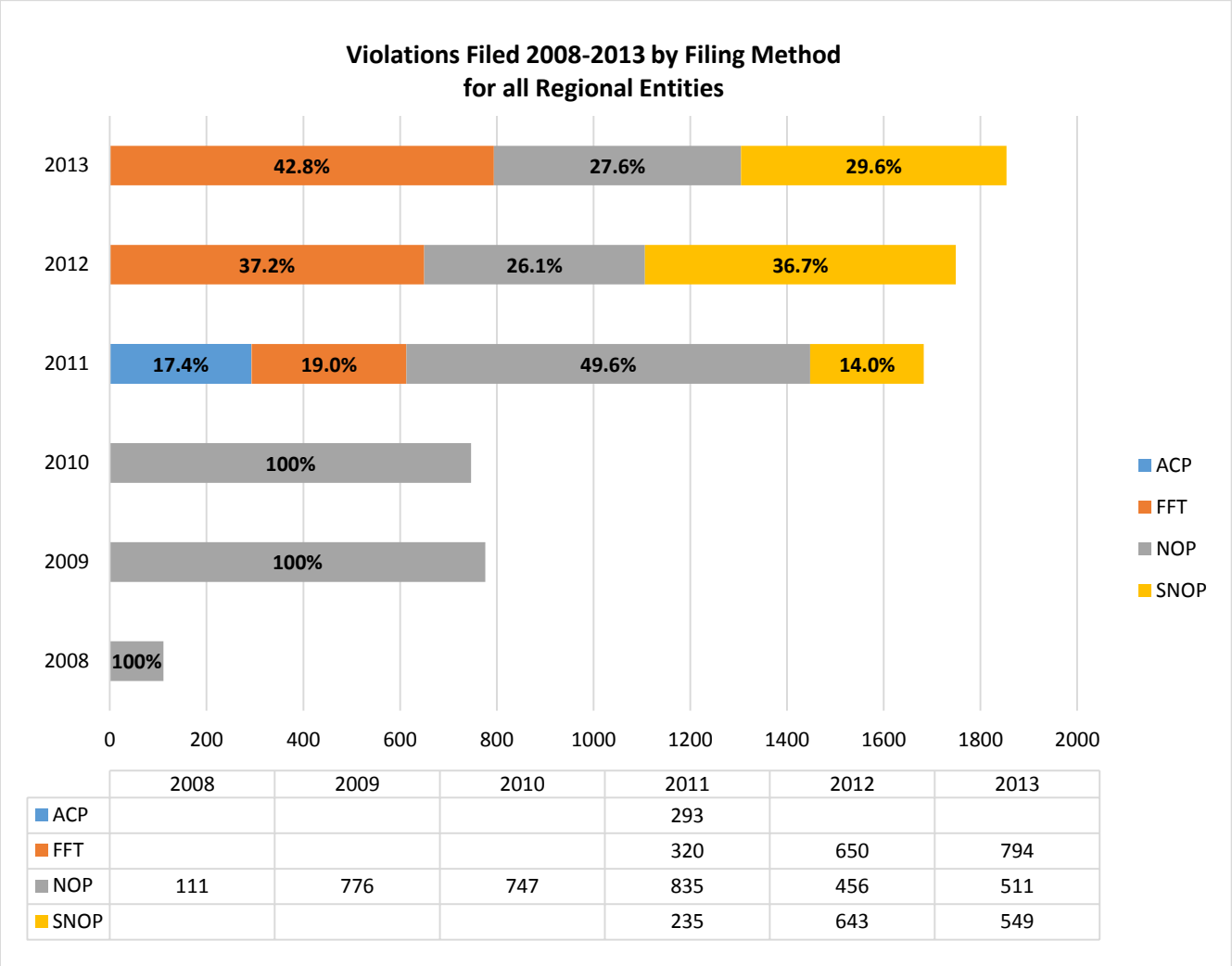
In 2014, NERC and the Regional Entities are continuing to work together to reduce the number of violations in inventory that are older than 24 months. These efforts will ensure that Regional Entities are prioritizing and resolving older violations appropriately. Combined with efforts to decrease processing times through the use of streamlined enforcement mechanisms and enforcement processing process refinements, the Regional Entities will reduce overall processing times and provide finality sooner to registered entities.

iv. Implementation of Streamlined Enforcement Processing Mechanisms

During the five-year assessment period, the Regional Entities worked with NERC to develop, refine, and implement process improvements to ensure the timely processing of new violations while also allowing for the reduction of the number of older violations. Most notable among these process improvements was the development of streamlined enforcement processing mechanisms that simplify the process of filing violations with the Commission. These mechanisms include the SNOP and the FFT program.

At the time of the three-year performance assessment, NERC and the Regional Entities used the NOP mechanism to process all violations. Using only the NOP format, 1,634 violations were filed with the Commission from 2008 through 2010. In 2011, following the implementation of the Administrative Citation Process (ACP) and the FFT and SNOP processes, the Regional Entities collectively filed 1,683 violations – more than the previous three years combined.[82]

Violations Filed per Year by Filing Method, 2008-2013



	2008	2009	2010	2011	2012	2013
ACP				293		
FFT				320	650	794
NOP	111	776	747	835	456	511
SNOP				235	643	549

In 2012, the Regional Entities continued the implementation of the FFT and SNOP processes, which, along with the NOP, are the three enforcement processing mechanisms in use today. During the assessment period, the ERO Enterprise caseload consisted primarily of violations posing a lower risk to the reliability of the BPS. The FFT and SNOP processes proved to be especially useful for processing these lower-risk violations.

[82] The ACP was an alternative enforcement processing mechanism used to process a number of lower risk violations in 2011. The format was similar to the SNOP format currently being used.

In 2012, the number of violations processed by means of SNOP or FFT increased after the Regional Entities developed knowledge and experience with the new mechanisms. These methods accounted for over 70% of the total filed violations in 2012 and 2013. NERC and the Regional Entities continued to use the NOP format for violations that posed a serious and substantial risk to reliability, required the completion of substantial above-and-beyond mitigating activities,[83] or presented other facts and circumstances requiring a detailed presentation. Going forward, NERC expects the proportion and use of the filing mechanisms to evolve as the ERO Enterprise implements the process refinements being developed under RAI.

In 2013, NERC and the Regional Entities worked together to expand the FFT program by implementing the latest round of FFT enhancements, which were approved by the Commission in an order issued June 20, 2013.[84] These enhancements will also reduce the amount of time required to process issues through the FFT program. As a result of these enhancements, FFT treatment is now available for a limited pool of possible violations posing a moderate risk to the reliability of the BPS (in addition to possible violations posing a minimal risk). In addition, certain unmitigated possible violations may be processed through the FFT program, so long as mitigation is completed within 90 days from the date the FFT item is posted.

To streamline processing of FFTs, Regional Entities now submit their FFTs for public posting on NERC's website at the end of each month. This replaces the prior requirement that NERC submit monthly informational filings to the Commission. NERC maintains its enforcement oversight by reviewing a representative sample of FFTs during the 60-day window following the public posting as well as through an annual spot check. NERC's spot checks ensure that issues selected for FFT treatment are appropriate for the program; that the issues are explained sufficiently in the posted documents; that the FFT program is implemented consistently across the regions, and that information about FFT issues is presented consistently across regions.

In addition to feedback provided through the spot check process, NERC provides ongoing training and guidance to the Regional Entities. Risk assessments play a large role in the FFT process and will be important to the success of the risk-based enforcement processes being implemented under RAI. In recognition of the importance of risk assessments, NERC provides ongoing training to the Regional Entities on how to evaluate the risk posed by an issue and how to document the results of the risk assessment in a clear and consistent manner. NERC also developed FFT templates to ensure that information regarding FFT issues, such as issue descriptions, mitigating activities, and other relevant information, is presented in a consistent manner across all Regional Entities. In addition, NERC, working with the Regional Entities, developed and posted an *ERO Self-Report User Guide*.[85] The *ERO Self-Report User Guide*

[83] As described in the evaluations of the individual Regional Entities, "above-and-beyond" activities refers to activities that a registered entity agrees to undertake as part of the resolution of an instance of noncompliance, in addition to completing a mitigation plan or other mitigating activities and/or paying a monetary penalty.

[84] *North American Electric Reliability Corporation*, *Order on Compliance Filing*, 143 FERC ¶ 61,253 (2013).

[85] Drafts of the *ERO Self-Report User Guide* and the companion *ERO Enterprise Mitigation Plan Guide* documents were posted for public comment in January 2014. The final user guides are posted on the RAI page on the NERC website at: http://www.nerc.com/pa/comp/Pages/Reliability-Assurance-Initiative.aspx.

provides registered entities with helpful guidance on assessing risk and communicating relevant information to the Regional Entities.

Additional information regarding the FFT process and NERC's oversight of it is provided below.

v. Implementation of Compliance Data Systems

As noted above, the Regional Entities have implemented compliance data systems to collect and track violation data. These systems interface with NERC's centralized database. At the Regional Entity level, these systems have enabled substantial enforcement processing efficiencies. At the NERC level, these systems have enhanced NERC's ability to identify compliance and enforcement trends and compile accurate metrics.

To ensure the quality, integrity, and completeness of the data that is submitted to NERC's centralized database, NERC and the Regional Entities worked together to create a series of business rules. NERC commends the Regional Entities for the resources and effort they have expended in developing these business rules and the associated systems. However, improvements remain to be made in ensuring that data submitted to NERC's centralized database meets the parameters of the business rules. NERC will continue to work with the Regional Entities to address these areas.

vi. Quality of Submitted Information

In the three-year performance assessment, NERC noted that Regional Entities needed to improve the thoroughness and accuracy of the information provided to NERC staff for review to meet NERC expectations and the requirements of Commission orders.[86] Since the filing of the three-year performance assessment in 2009, NERC and the Regional Entities have taken concrete steps to improve the quality, clarity, and consistency of enforcement-related documentation. NERC considers these efforts to have been successful.

NERC developed a series of enforcement processing templates to assist the Regional Entities in ensuring that all required information is presented in a consistent and easily-understood format. Generally, the Regional Entities provide information in the requested format, using the templates, with the record documents that are necessary for filing.[87] The implementation of the various templates has improved the quality of submitted information since the three-year performance assessment.

However, through its regular review of submitted information, NERC has identified opportunities for further improvement. In particular, descriptions of the facts of each violation, assessments of the risk posed by each violation, and descriptions of factors contributing toward the imposition of a certain dollar penalty are not always clear or complete when violations are submitted to NERC for review in settlement agreements or NOCV. Specifically, Regional Entities

[86] *Three-Year ERO Performance Assessment Report*, Attachment 3 at 12.

[87] NERC has advised the Regional Entities to submit all necessary documentation at the time the NOCV or settlement agreement is submitted to NERC for review and BOTCC approval, where possible.

should explain fully what factors were considered aggravating, which factors were considered mitigating, and when previous violations of the same or similar Reliability Standards were or were not considered aggravating (and why). Careful and complete drafting will facilitate greater transparency of Regional Entity decision-making, an area noted for improvement by the commenters.[88] In addition, careful and complete drafting will avoid protracted follow-up periods and processing delays.

Through NERC's outreach efforts and other process improvements and guidance being implemented under RAI, NERC expects that the quality and clarity of risk assessment, violation description information, and other information relevant to enforcement processes will continue to improve. For example, NERC and the Regional Entities have developed two documents to enhance communication between registered entities and the Regional Entities and to facilitate the shift toward a risk-based enforcement approach. The first document, the *ERO Self-Report User Guide*, provides registered entities with additional insight into the information NERC and the Regional Entities need to provide efficient and timely resolution of instances of potential noncompliance. The second document, the *ERO Enterprise Mitigation Plan Guide*, provides guidance on the information that should be considered when developing a mitigation plan and the elements and analysis that should be included. Although targeted specifically to registered entities, the user guides also provide guidance and insight to Regional Entity auditors, new enforcement staff, and other stakeholders.

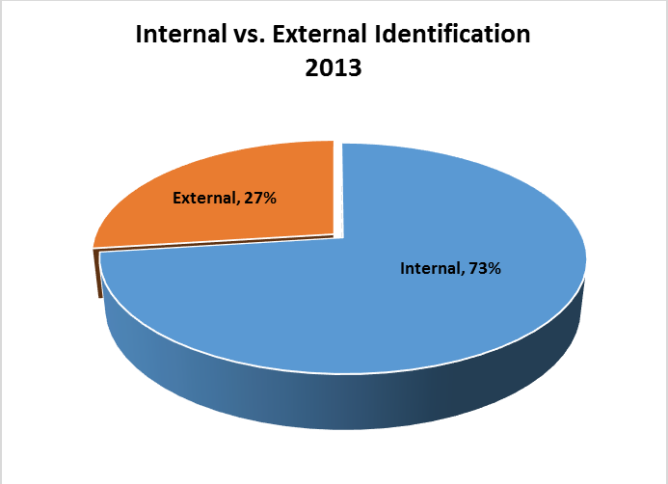
c. Improving Reliability Across the ERO Enterprise

i. Encouraging Internal Discovery of Violations

Regional Entity enforcement programs play an important role in improving the reliability of the BPS. Early self-identification, self-reporting, and mitigation of noncompliance are important steps in improving electric reliability. By deploying incentives to encourage the self-discovery and timely self-reporting of violations, the Regional Entities have encouraged registered entities to take proactive steps to self-identify their noncompliance and thereby promote a more reliable BPS.

[88] *See* the stakeholder comments summarized in the "Enforcement" sections of the comment and response tables in **Attachment 4**.

Percentage of Violations by Method of Identification, 2013



In 2013, internally-discovered (i.e., self-reported) violations comprised the majority of violations identified across the ERO Enterprise.

NERC recognizes that the percentage of self-identified violations necessarily depends on the number of violations identified by the Regional Entities through other compliance monitoring methods (i.e. spot checks and compliance audits). As NERC and the Regional Entities work together to implement efficiency and consistency-enhancing improvements under the compliance components of RAI, NERC expects to gain additional insight into audit finding and self-reporting trends across the Regional Entities. NERC expects that, as the ERO Enterprise gains experience in evaluating the internal controls and management practices of registered entities, it will develop a better understanding of what factors drive internal self-identification of violations. This insight will allow NERC and the Regional Entities to refine self-reporting incentives appropriately.

ii. Ensuring the Timely Mitigation of Violations

NERC monitors all items with ongoing mitigating activities regardless of where the violations are in the enforcement process and expects mitigating activities to be completed in a timely manner.[89] Throughout the assessment period, the Regional Entities worked to ensure that violations, including older violations that have not yet been processed, are mitigated and no longer pose a risk to reliability.

[89] As defined in the NERC ROP, Appendix 2, "mitigating activities" means actions taken by a registered entity to correct and prevent recurrence of a noncompliance, whether or not the actions are embodied in a mitigation plan.

Status of Mitigating Activity for Violations Discovered from 2007-2013 and Requiring Mitigation for the ERO Enterprise as of December 31, 2013[90]

Year of Discovery	% Completed	% in Progress
2013	36.0%	64.0%
2012	79.6%	20.4%
2011	92.4%	7.6%
2010	96.4%	3.6%
2009	100.0%	0.0%
2008	99.6%	0.4%
2007	100.0%	0.0%
Grand Total	**84.6%**	**15.4%**

However, as the above chart demonstrates, a small number of older violations remain for which mitigating activities have not been completed. For these violations, mitigating activities may have been started, but not yet completed. Further, some of the older violations with open mitigation relate to registered entities for which violations cannot be processed as a result of a pending court dispute.

In 2014, NERC will continue to focus on the completion of mitigating activities and track this closely. NERC will measure the success of each Regional Entity and the ERO Enterprise as a whole in ensuring that violations are mitigated and no longer pose a threat to reliability.

iii. Promoting Reliability through Enforcement Philosophy and Practices

The Regional Entities have encouraged registered entities to proffer "above-and-beyond" mitigating activities in lieu of, or as an offset to, the full monetary penalties assessed pursuant to the NERC *Sanction Guidelines*. By encouraging registered entities to invest in improvements beyond those necessary to ensure compliance with violated Reliability Standards, this enforcement approach improves reliability and reduces the likelihood of future noncompliance. Examples of such above-and-beyond activities are provided in the individual Regional Entity assessments below.

d. NERC'S Ongoing Monitoring of Specific Regional Entity Processes Under the CMEP

NERC Enforcement staff uses its oversight role to ensure that the Regional Entities are implementing the CMEP effectively, to provide constructive feedback where appropriate, to identify trends, and to drive the implementation of best practices. Over time, as enforcement

[90] This table reports the percentage of violations discovered from the years 2007 through 2013 with completed or open mitigation for all Regional Entities and NERC acting as the CEA as of December 31, 2013. This table excludes dismissed violations and non-U.S. violations.

processes and organizations evolved and matured, NERC's oversight role has evolved and matured. As the Regional Entities have demonstrated the adequacy and maturity of their enforcement-related processes and procedures, NERC has adjusted its oversight activities. For example, whereas NERC formerly reviewed all FFTs before filing with the Commission, NERC now reviews only a representative sample of FFTs that have been posted to NERC's website.[91] In addition, following a 2013 spot check of Regional Entity dismissal procedures, NERC no longer requires preapproval of letters of dismissal for externally-discovered violations (except for violations arising from compliance investigations).

NERC continually looks for ways to exercise its oversight role to drive improvement in Regional Entity processes and its own oversight processes. The results of several of NERC's oversight activities are presented below and in the individual Regional Entity sections of this evaluation.

During the assessment period, NERC conducted spot checks of different aspects of the Regional Entities' implementation of the CMEP. As examples of the types of spot checks it performed, NERC reviewed Regional Entity dismissal procedures in 2013. This spot check provided valuable insight into the reasons why self-reported violations are dismissed.[92] The spot check also gave NERC the opportunity to examine Regional Entity dismissal procedures and documentation in depth. Based on its analysis of the spot check results, NERC concluded that the Regional Entities are preparing letters of dismissals that generally communicate the reasons for dismissal to the registered entities. NERC prepared several letter of dismissal templates to assist Regional Entities in ensuring that the letters of dismissal contain all required information on a consistent basis.

NERC engages in various activities to ensure consistency and exercise oversight over the FFT process. Public and nonpublic versions of the FFTs are submitted by the Regional Entities to NERC, in the NERC-provided template, for posting on a monthly basis. NERC staff reviews moderate risk issues for suitability for FFT filing. If NERC staff determines that the moderate risk issues are not appropriate for FFT filing, staff will discuss concerns with Regional Entity staff. NERC, concurrently with the Commission, reviews a representative sample of FFTs during the 60-day window following the posting of the FFT on NERC's website. NERC also includes moderate-risk FFTs and FFTs with ongoing mitigation as part of its review. Following its review

[91] As noted above, NERC's oversight of the FFT program consists of a review during the 60-day window following the monthly FFT posting as well as an annual spot check.

[92] NERC concluded that 67% of dismissals from its randomly-selected sample were attributable to an expansion of scope or a duplication of already-existing violations. In 22% of dismissals, the registered entity submitted additional information supporting compliance after the initial determination of possible violation was made. Approximately 11% of the dismissals were attributable to changes in the applicable Reliability Standard and requirement, transfer to another CEA, or administrative reasons.

NERC expects the number of dismissals to decrease as a result of the implementation of enhancements to the preliminary screen process in December 2012 (this process requires Regional Entities to review new noncompliance and determine whether it is a duplicate of a violation already being processed) and the issuance of the *ERO Self-Report User Guide*.

of the FFT samples, NERC coordinates any questions or concerns it may have with FERC staff, which conducts an independent sampling and review during the same 60-day period.

In addition to sampling during this 60-day review period, NERC also conducts a separate sampling of the FFTs to gather information related to NERC's annual filing with the Commission. In late 2012, NERC initiated a review of the Regional Entities' FFT programs, the results of which were detailed in NERC's March 15, 2013 compliance filing and report.[93]

During the first quarter of 2014, NERC Enforcement staff performed another review of the Regional Entities' FFT programs, the results of which were detailed in NERC's June 20, 2014 compliance filing and report.[94] In summary, NERC found that the quality of the FFTs submitted by the Regional Entities for posting has continued to improve from the FFTs submitted to NERC for review in prior years. NERC also found that the Regional Entities are appropriately selecting issues for FFT treatment. However, NERC identified additional areas for improvement to promote accuracy and consistency in implementation of the FFT program, as described in detail in that filing.

In addition to its periodic spot checks, NERC performs regular oversight of certain Regional Entity enforcement processes. For example, NERC reviews all SNOP violations and NOP violations before filing these violations with the Commission, and it provides feedback to the Regional Entities as appropriate. As part of this review, NERC reviews all proposed penalties for appropriateness and consistency with monetary penalties assessed for violations of the same Reliability Standard and requirement occurring under similar facts and circumstances, in accordance with the principles contained in the NERC *Sanction Guidelines.*

e. Conclusion

The Regional Entities have made substantial progress during the five-year assessment period in improving the efficiency and timeliness of enforcement processing. Going forward, each of the Regional Entities should focus on continuing to prioritize older violations for completion of processing, ensuring that all violations are mitigated in a timely manner, and ensuring the quality of data and information that is submitted to NERC in the compliance data information systems and in settlement agreements and NOCV. Further, each of the Regional Entities should implement the process improvements recommended by NERC through its oversight activities.

[93] *Compliance Filing and Report on the Compliance Enforcement Initiative and Proposed Enhancements to the Fix, Fix, Track and Report (FFT) Program*, Docket No. RC11-6-004 (Mar. 15, 2013).

[94] *North American Electric Reliability Corporation's Compliance Filing and Report on the Find, Fix, Track and Report Program*, filed June 20, 2014, in Docket No. RC11-6-004.

2. Evaluation of Florida Reliability Coordinating Council, Inc.

a. Overview

In the three-year performance assessment, NERC concluded that FRCC needed to improve its timeliness in enforcement processing in several respects.[95] In response, during the assessment period, FRCC has taken several steps to address the concerns identified by NERC. FRCC added personnel to its enforcement staff and developed a number of processes to support and facilitate the processing of violations. FRCC has also developed checklists, flowcharts, caseload goals, and automated database reporting tools.[96]

During the assessment period, FRCC has increased the number of FTE staff dedicated to enforcement from 0 FTEs in 2009 to 4 FTEs as of December 31, 2013. Based on FRCC's processing speed and efficiency as measured at the end of the assessment period, NERC views FRCC's enforcement staffing to be sufficient to process the number of violations that it receives.

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FRCC ended the assessment period with a Caseload Index that was consistent with the ERO Enterprise Caseload Index. FRCC processed all violations discovered before 2012, in furtherance of an ERO Enterprise goal. FRCC's caseload tends to consist of more-recent violations, and FRCC has made progress in ensuring the completion of mitigation for older violations. Finally, NERC has reviewed FRCC's enforcement-related processes as part of its oversight role and found that, while areas for improvement remain, FRCC generally implements those processes in a satisfactory manner.

In addition, FRCC staff have actively participated in the development of RAI. FRCC staff have participated in the Aggregation of Minimal Risk Issues and Enforcement Discretion pilot programs and served on the *ERO Self-Report User Guide* and *ERO Enterprise Mitigation Plan Guide* drafting teams. This participation is vital as the ERO Enterprise shifts toward a risk-based model of compliance and enforcement.

As explained more fully below, based on FRCC's Caseload Index, FRCC's successful processing of its older violations (as facilitated by its effective implementation of streamlined enforcement processing mechanisms), and the results of NERC's oversight activities, NERC concludes that FRCC has performed as an effective Regional Entity with respect to enforcement activities during the assessment period. NERC will continue to work with FRCC to ensure that violations are mitigated promptly, with an added emphasis on ensuring the completion of mitigation for older violations.

[95] *Three-Year ERO Performance Assessment Report*, Attachment 3 at 16.

[96] 2014 JRESA Appendix 2B at 1-2.

b. Evaluation of Caseload Processing Efficiency

i. The Composition of FRCC's Caseload

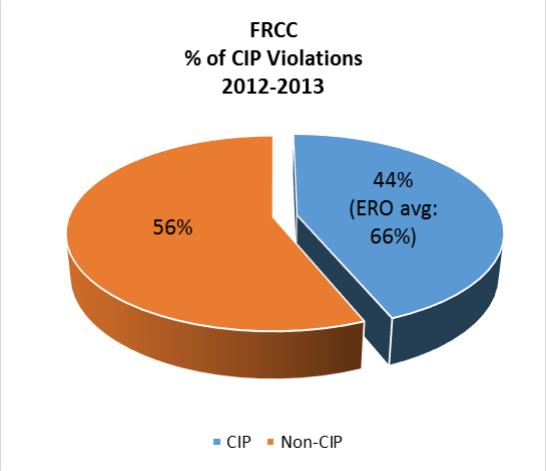
During the assessment period, FRCC reported 568 violations to NERC.

Violations for FRCC 2009-2013 by Year Reported to NERC[97]

Year Reported to NERC	Violations Reported
2009	188
2010	109
2011	141
2012	69
2013	61
Total	**568**

As shown in the table above, FRCC reported a relatively high number of violations in 2009, with a significant drop occurring after 2011. In 2011, over 70% of total violations were of the CIP Reliability Standards. In the years 2012 and 2013, violations of CIP Reliability Standards represented 44% of total violations; this is a substantially lower percentage than the ERO Enterprise average.

Type of Violations Reported to NERC by FRCC, 2012-2013



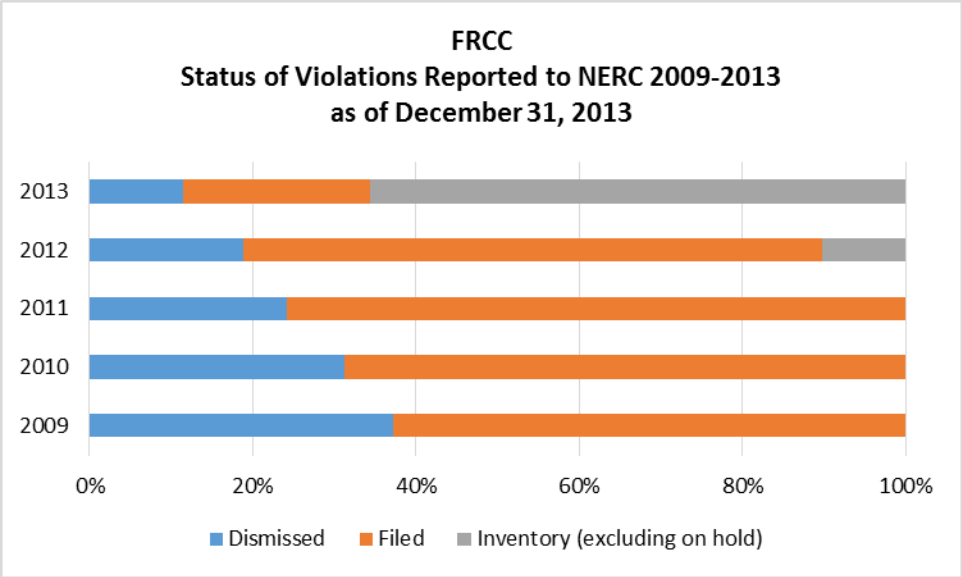
FRCC believes that the lower-than-average ratio of CIP violations in 2012 and 2013 may be due to two factors. During 2011, FRCC performed spot checks on all registered entities within the FRCC region that had critical cyber assets. As a result, FRCC had a high ratio of CIP violations

[97] For an explanation of the methodology used to calculate the data in this table and throughout this §II.D, *see supra* n. 766.

for that year (approximately 75%). In addition, FRCC believes that it has a lower percentage of registered entities with critical cyber assets than other Regional Entities.

Of the total violations reported to NERC by FRCC during the assessment period, 47 violations, or approximately 8%, remained to be processed as of December 31, 2013 (excluding on-hold violations). As shown in the table below, FRCC has processed all violations reported to NERC in 2009, 2010, and 2011. FRCC processed 90% of violations reported to NERC in 2012.

Status of Violations Reported to NERC 2009-2013 for FRCC



FRCC processed 34% of violations reported to NERC in 2013. This was somewhat lower than the ERO 2013 processing rate of 39%. However, violations reported to NERC in 2013 represent approximately 85% of the violations available for processing in FRCC's caseload, which compares favorably to the overall ERO Enterprise average of 67%. FRCC appears to be moving toward a caseload consisting primarily of newer violations.

ii. Caseload Index

The Caseload Index for FRCC is 7.3 months as of December 31, 2013. This is consistent with the ERO Enterprise Caseload Index of approximately 6.5 months.

Based on its achievements in processing its caseload to date and its Caseload Index, it appears that FRCC's efforts to strengthen and streamline its enforcement processes during the assessment period have been effective.

iii. Efforts to Reduce Older Caseload

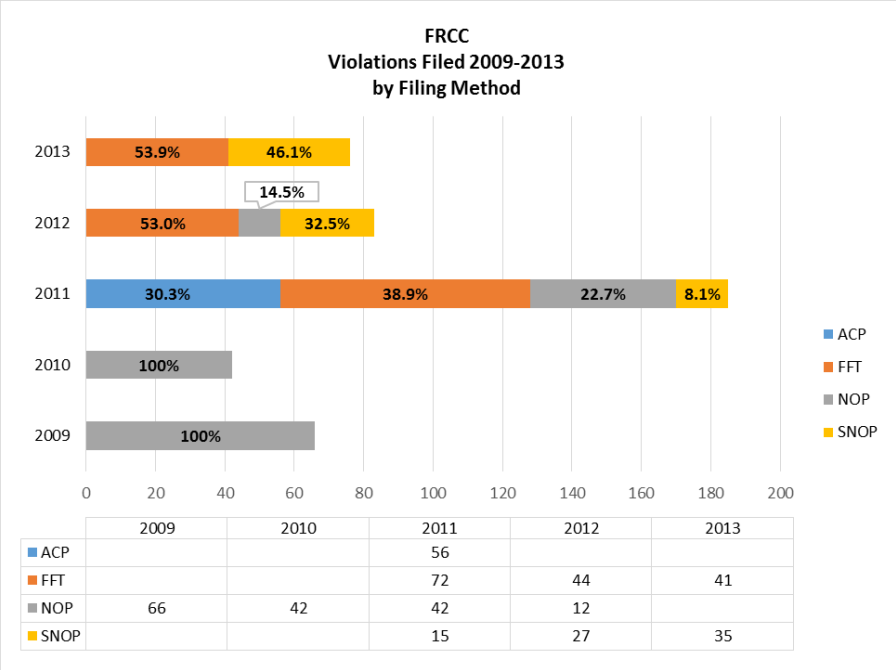
In 2013, FRCC processed all remaining cases in its pre-2012 caseload. NERC commends FRCC for its responsiveness and efforts to achieve this important ERO Enterprise goal.

Based on the current composition of its inventory of violations available to be processed and its successful efforts in processing its older violations, FRCC is especially well-positioned to achieve the goal of ensuring that violations are processed before reaching 24 months in age.

iv. Implementation of Streamlined Enforcement Processing Mechanisms

FRCC effectively used streamlined processing mechanisms to process a substantial portion of its caseload during the assessment period. In 2011, following the implementation of these mechanisms, FRCC filed 185 violations – more than the previous two years combined.

Violations Filed per Year by Filing Method for FRCC, 2009-2013



	2009	2010	2011	2012	2013
ACP			56		
FFT			72	44	41
NOP	66	42	42	12	
SNOP			15	27	35

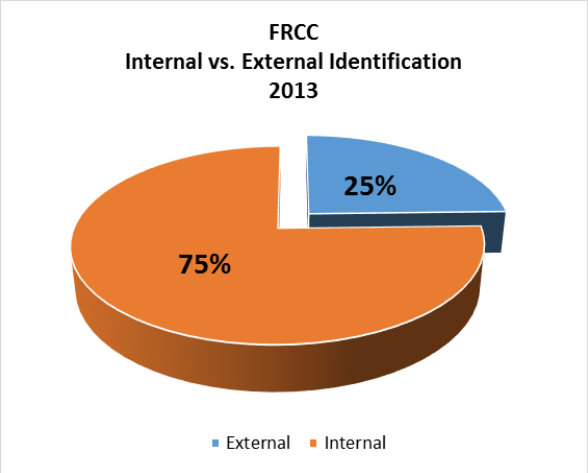
By 2013, FRCC filed all of its violations using either SNOP or FFT. NERC expects that FRCC will continue to reserve the NOP format for violations that require NOP treatment and will take advantage of further process refinements available under RAI. Additional information regarding FRCC's application of FFT is presented later in this assessment.

c. Improving Reliability

i. Encouraging Internal Discovery of Violations

In 2013, violations discovered by registered entities through internal mechanisms comprised 75% of total violations in the FRCC region.

Percentage of Violations by Method of Identification for FRCC in 2013



This is consistent with the ERO Enterprise average of 73%.

ii. Ensuring the Timely Mitigation of Violations

FRCC reported that it takes several steps to encourage the prompt submission of mitigation plans or mitigating activities. First, FRCC encourages registered entities to submit the mitigating activities that are planned or which have been completed as part of the registered entity's submission of a self-report or self-certification. FRCC also encourages registered entities to submit mitigation plans early, before the issuance of a Notice of Alleged Violation. Second, FRCC enforcement staff contacts each registered entity to encourage the submission of a mitigation plan approximately ten days after the issuance of a Notice of Possible Violation. FRCC also encourages registered entities to submit draft mitigation plans for review by FRCC staff before formal submission. In evaluating the sufficiency of a registered entity's proposed mitigation, FRCC carefully considers the time it will take to mitigate the violation and the steps taken to prevent reoccurrence of violations. In 2013, FRCC reported that it continued to see some improvement in the timeliness and quality of mitigating activities and mitigation plans submitted by most registered entities, and that most registered entities within its region were willing to work with FRCC staff to create mitigation plans that would be acceptable to FRCC earlier in the mitigation process.

As demonstrated in the table below, FRCC has made substantial progress in ensuring that violations from 2007 through 2010 have been mitigated. However, approximately four violations from 2011 had open mitigation plans at the end of the assessment period. FRCC reported that in those cases, the registered entities had mitigated the violations and completed all milestones required of their mitigation plans; however, they had not yet certified the completion of their mitigation plans and supplied evidence for FRCC to verify completion.

FRCC: Status of Mitigating Activity for Violations Discovered from 2007-2013 and Requiring Mitigation as of December 31, 2013[98]

Year of Discovery	% of Violations with Completed Mitigation Plans or Activities	% of Violations with Mitigation in Progress
2013	25.0%	75.0%
2012	89.3%	10.7%
2011	96.0%	4.0%
2010	100.0%	0.0%
2009	100.0%	0.0%
2008	100.0%	0.0%
2007	100.0%	0.0%
Grand Total	**89.6%**	**10.4%**

In addition, approximately three-quarters of violations discovered in 2013 had open mitigation plans by the end of the year. FRCC reported that in many of these newer cases, the violation had been mitigated, but the registered entity did not yet certify completion or submit completion evidence to FRCC for verification. NERC will continue to work with FRCC to ensure that mitigation of violations is completed in a timely manner.

iii. Promoting Reliability through Enforcement Philosophy and Practices

FRCC's enforcement philosophy consists of the following components. FRCC provides training and communication to registered entities to help them understand and be more compliant with the Reliability Standards. FRCC strives for efficiency in disposition processing and fairness throughout the enforcement process, and it commits to maintain open communication with registered entities.

In its settlement processes, FRCC has worked with registered entities, where appropriate, to accept the completion of certain activities above-and-beyond those required to ensure compliance with one or more Reliability Standards in lieu of the full monetary penalties permitted by the NERC *Sanction Guidelines*. FRCC reported that it typically performs a thorough review and critique of a registered entity's internal compliance program as part of settlement discussions, and that registered entities within its region have frequently committed to initiating actions within their organizations to improve their compliance programs. Registered entities in the FRCC region have committed to: (i) implementing software applications; (ii) creating, improving, or disseminating programs relating to internal controls; (iii) creating compliance job positions; (iv) developing and delivering presentations for FRCC compliance workshops; and (v) hiring contractors to evaluate and make recommendations for the development of a sustainability plan

[98] This table reports the percentage of violations discovered from the years 2007 through 2013 with completed or open mitigation. This table excludes dismissed violations.

and training regarding internal control processes. These efforts allow registered entities to allocate their resources to those projects that can increase overall reliability and reduce the likelihood of future noncompliance. NERC encourages FRCC to continue deploying solutions such as these that promote reliability and insight into processes that can manage risk.

d. FRCC'S Implementation of Various Aspects of the CMEP

As noted in §II.D.1.a above, NERC conducts ongoing oversight activities to evaluate the effectiveness of each Regional Entity's implementation of the CMEP. These activities include regular reviews and periodic spot checks of specific Regional Entity processes. NERC's oversight activities give NERC an ongoing view into how effectively and efficiently the Regional Entity is executing its enforcement responsibilities. Below is a summary of some of NERC's more recent oversight activities specific to FRCC.

FRCC has adopted the NERC CMEP as the basis for providing fair and impartial procedures for enforcement. With respect to assessing penalties, FRCC follows NERC guidance.[99] FRCC reviews a registered entity's internal compliance program and its impact on the violations being processed. FRCC includes consideration of the internal controls that a registered entity may have in place as a part of this review. NERC reviews all penalties submitted by FRCC for appropriateness and consistency with monetary penalties assessed by FRCC and by other Regional Entities for violations of the same Reliability Standards and Requirements occurring under similar facts and circumstances. NERC has found that FRCC assesses monetary penalties that are appropriate and consistent with penalties assessed for similar violations.

Based on a spot check in 2013, NERC determined that FRCC dismisses violations for appropriate reasons and generally includes the required information when issuing letters of dismissal. NERC identified opportunities where FRCC could improve its letters of dismissal and communicated those opportunities to FRCC. By implementing the recommended improvements, FRCC can improve the quality of its compliance guidance to registered entities.

As part of its ongoing FFT review processes, NERC reviewed a sample of FFT issues filed or posted by FRCC during the assessment period to examine FRCC's procedures for FFT processing and the application of those procedures to the FFT issues in its caseload. Following its review, NERC concluded that FRCC's process documents provide clear and concise guidance for FFT processing and drafting and follow the NERC guidance. Further, NERC concluded that FRCC consistently applies the processes set forth in its process documents, and that FRCC applied FFT treatment and evaluated risk in a consistent manner. NERC noted several ways that FRCC could improve its FFT postings and related documentation to provide additional transparency to its determinations.

e. Conclusion

Based on NERC's review of the factors described above, NERC concludes that FRCC has performed as an effective Regional Entity with respect to enforcement activities during the

[99] 2014 JRESA, Appendix 2-C at 11.

assessment period. FRCC should adopt the recommendations for improvement provided as part of NERC's oversight activities.

3. Evaluation of Midwest Reliability Organization

a. Overview

In the three-year performance assessment, NERC concluded that MRO was an effective Regional Entity as demonstrated by several metrics.[100] At the time NERC noted that MRO needed to improve on providing accurate statements of fact for each violation, assessing penalties according to the facts of each situation as required by FERC orders, and ensuring consistency in its practices with NERC practice and the practice of other Regional Entities.[101]

Consistent with the trends across the ERO Enterprise, the quality of information submitted by MRO for NERC review has improved during the assessment period. Further, MRO believes that its three-step process that segregates duties among its Compliance Monitoring, Risk Assessment and Mitigation, and Enforcement teams, which it established in 2009, provides a "high level of assurance that determinations are accurate, fair and non-discriminatory."[102]

During the assessment period, MRO has increased the number of FTE staff dedicated to enforcement from 2.46 FTEs in 2009 to 4 FTEs as of December 31, 2013. In addition, MRO's Risk Assessment and Mitigation staff consisted of 1 FTE in 2009, and as of December 31, 2013 it consists of 6.25 FTEs (including two open positions). MRO's proposed 2015 Business Plan and Budget anticipates an additional 1.35 FTEs in these two groups. Based on MRO's processing speed and efficiency as measured at the end of the assessment period, NERC views MRO's historic staffing to be insufficient to process the number of violations that it receives in accordance with the performance objectives of the ERO Enterprise. However, MRO has taken steps to increase its staffing throughout the assessment period and beyond into 2014 and 2015.

NERC recognizes the progress MRO has made in enforcement processing during the assessment period. NERC also recognizes that MRO often takes the lead in settlement negotiations to resolve violations from MRREs, and that MRO has demonstrated a commitment to use the enforcement process to promote the reliability of the BPS. Further, NERC has reviewed MRO's enforcement-related processes as part of its oversight role and found that, while areas for improvement remain, MRO generally implements those processes in a satisfactory manner. However, MRO ended the assessment period with a Caseload Index that was much higher than the ERO Enterprise Caseload Index. NERC and MRO believe that, with the additional staff MRO expects to add, MRO's processing times (and its Caseload Index) will improve.

In addition, MRO made substantial strides in reducing the portion of its caseload consisting of violations dating to before 2012. While MRO still has older violations in its inventory that must

[100] *Three-Year ERO Performance Assessment Report*, Attachment 3 at 18.

[101] *Id*.

[102] 2014 JRESA, Appendix 2-B at 2-3.

be processed and mitigated, NERC is working with MRO to accomplish the ERO Enterprise goal of having no cases older than 24 months in inventory at the end of 2014.

NERC recognizes the substantial contributions MRO staff have made in the development of RAI and the related enforcement pilot programs. MRO has taken a leadership role in the conceptualization, development, and testing of several programs, and a member of MRO's staff led the multi-region working group on enforcement activities. This participation is vital as the ERO Enterprise shifts toward a risk-based model of compliance and enforcement.

In light of all of the relevant factors, which are explained more fully below, NERC concludes that MRO has performed as an effective Regional Entity with respect to enforcement activities during the assessment period. However, substantial improvement remains to be made with respect to MRO's enforcement processing time as measured by the Caseload Index metric.

b. Evaluation of Caseload Processing Efficiency

i. The Composition of MRO's Caseload

During the assessment period, MRO reported 664 violations to NERC.[103]

Violations for MRO 2009-2013 by Year Reported to NERC[104]

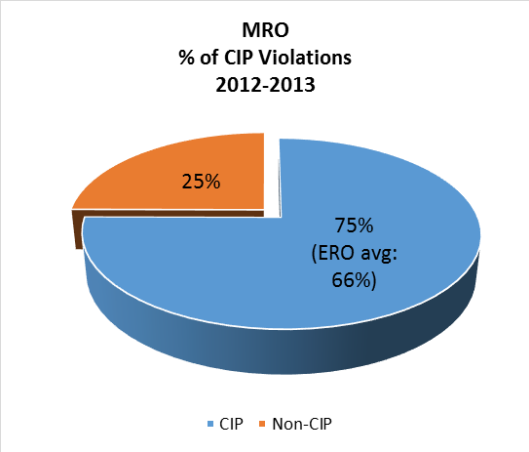
Year Reported to NERC	Violations Reported
2009	60
2010	103
2011	196
2012	166
2013	139
Total	**664**

As noted in the table above, the highest number of violations reported to NERC by MRO was in 2011, with the number decreasing by 29% in 2013. Most of the violations in 2011 were of the CIP Reliability Standards. In the years 2012 and 2013, violations of CIP Reliability Standards represented 75% of total violations; this is a higher percentage than the ERO Enterprise average of 66%.

[103] This table reflects U.S. violations only. When including Canadian violations, MRO received 693 violations for evaluation and processing from 2009 through 2013.

[104] For an explanation of the methodology used to calculate the data in this table and throughout this §II.D, *see supra* n. 766.

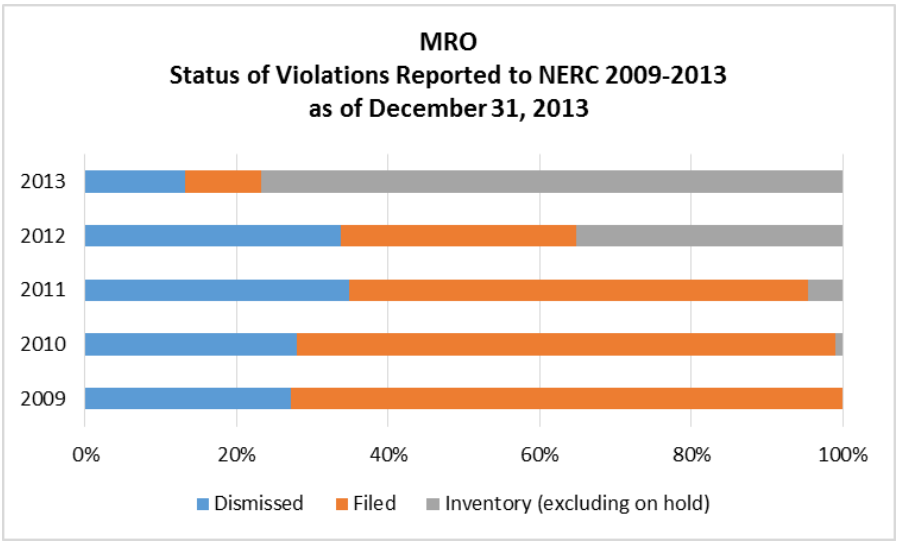
Type of Violations Reported to NERC by MRO, 2012-2013



The discovery method of the CIP violations was fairly evenly split between external and internal methods of identification.

Of the total violations reported to NERC during the assessment period, approximately 159 violations, or 24%, remained to be processed as of December 31, 2013. As demonstrated in the table below, MRO has processed all violations that it reported to NERC in 2009. MRO has processed approximately 99% of violations reported to NERC in 2010, 95% of violations reported to NERC in 2011, and 65% of violations reported to NERC in 2012.

Status of Violations Reported to NERC 2009-2013 for MRO



MRO processed approximately 23% of violations reported to NERC in 2013. This is lower than the ERO 2013 processing rate of 39%. Further, the percentage of MRO's caseload consisting of violations reported to NERC in 2013, approximately 62.3%, is slightly lower than the overall ERO Enterprise average of 67%.

ii. Caseload Index

The Caseload Index for MRO was 14.3 months as of December 31, 2013, compared to the ERO Enterprise Caseload Index of approximately 6.5 months.

MRO believes that its Caseload Index is higher than the ERO Enterprise average due to several factors. MRO states that it places a premium on gaining a comprehensive understanding of the violation and developing mitigation plans that reduce the risk of recurrence, which can be time consuming and increases MRO's Caseload Index. MRO reported a number of violations of CIP-005 and CIP-007, which often require longer processing times due to the need to ensure that the risk is understood and is being comprehensively addressed. Additionally, MRO's risk assessment staff is heavily involved in RAI development efforts.

In light of MRO's Caseload Index and as reflected in the characteristics of its caseload (i.e., MRO's caseload consists of a greater portion of older violations than other Regional Entities), NERC encourages MRO to implement measures so that it is better equipped to process violations as it receives them. MRO currently has two open positions in its Risk Assessment and Mitigation group which, when filled, will help MRO improve its Caseload Index. In addition, MRO created the position of CMEP process principal. This position is responsible for quality assurance and oversight of MRO's business practices related to compliance monitoring and enforcement, including internal transitions among the compliance, risk assessment and mitigation, and enforcement groups. MRO believes it will achieve greater efficiency, enhance communication, and ensure repeatability of its CMEP-related activities through this position. MRO also believes that the increase in staffing will allow it to improve processing times while maintaining its dedication to gaining a complete understanding of violations in its region and examining the best ways to prevent reoccurrence. NERC will work with MRO to evaluate the effectiveness of this and other measures taken to improve efficiency in MRO's enforcement processes.

iii. Efforts to Reduce Older Caseload

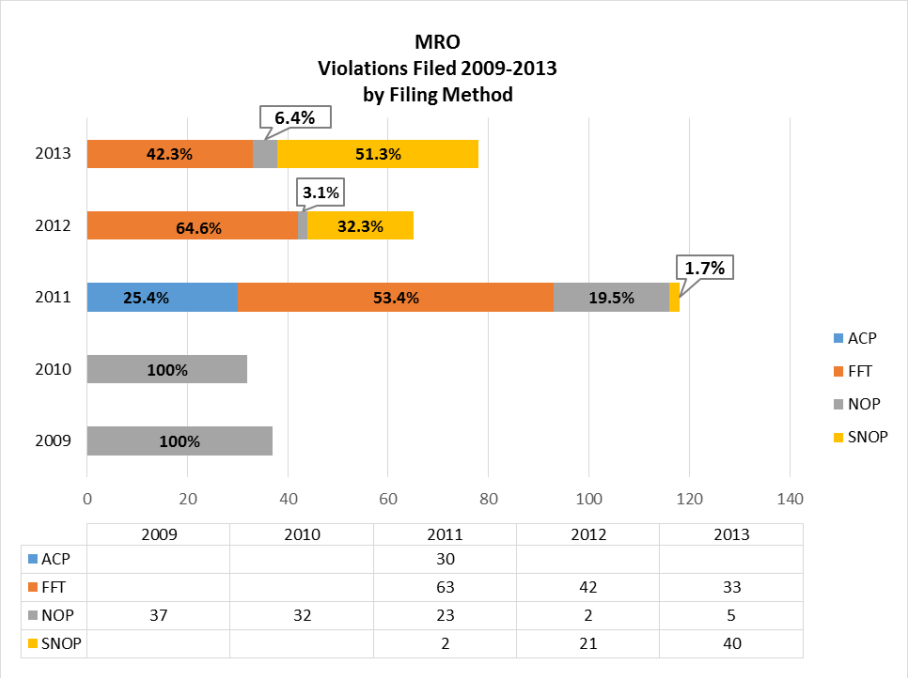
In 2013, MRO reduced the portion of its caseload consisting of violations dating to before 2012 by 89%. NERC commends MRO for its responsiveness and efforts to achieve this important ERO Enterprise goal. MRO states that its remaining inventory consisted of particularly complex violations, and that it is committed to having all 2012 and older cases resolved by the end of 2014.

NERC will work with MRO to ensure that these and other older violations are resolved as soon as is practicable in light of the facts of each violation.

iv. Implementation of Streamlined Enforcement Processing Mechanisms

MRO effectively used streamlined enforcement processing mechanisms to process a substantial portion of its caseload during the assessment period. In 2011, following the implementation of the streamlined enforcement processing mechanisms, MRO filed 118 violations – more than the previous two years combined.

Violations Filed per Year by Filing Method for MRO, 2009-2013



	2009	2010	2011	2012	2013
ACP			30		
FFT			63	42	33
NOP	37	32	23	2	5
SNOP			2	21	40

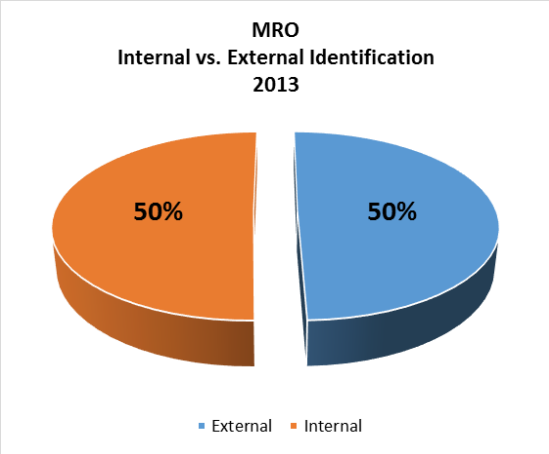
MRO has used the streamlined processing mechanisms to file over 88% of violations since 2011. MRO is using the FFT process to resolve violations posing a minimal risk to the BPS, and it seeks to use the enforcement mechanisms in a manner that promotes consistency. NERC expects that MRO will continue to reserve the NOP format for violations that require it and take advantage of further process refinements available under RAI. Additional information regarding MRO's implementation of FFT is presented later in this assessment.

c. Improving Reliability

i. Encouraging Internal Discovery of Violations

In 2013, violations discovered by registered entities through internal mechanisms comprised approximately 50% of total violations in the MRO region. This is lower than the ERO Enterprise average of 73%. Stated differently, during the assessment period, MRO discovered a higher percentage of violations through external methods (i.e., compliance audit and spot check) than other Regional Entities.

Percentage of Violations by Method of Identification for MRO in 2013



As noted above, NERC and the Regional Entities are working to understand the regional variations in the percentages of noncompliances discovered through self-discovery and audits across the ERO Enterprise. Understanding these differences, and how they may relate to registered entity internal controls and management practices, will allow NERC and the Regional Entities to continue to provide the right incentives for discovering and self-reporting noncompliances.

ii. Ensuring the Timely Mitigation of Violations

MRO reported that, upon validation of a violation, MRO mitigation staff conduct a thorough review of the present circumstances at the registered entity to ensure better, more effective corrective actions for prevention. MRO mitigation staff collaborate with the registered entities to develop a thorough, comprehensive, and effective mitigation plan that includes documentation and implementation of controls that are used to monitor performance and correct deficiencies to help prevent recurrence of noncompliance. MRO's position is that while it recognizes that prompt submission or early completion of mitigation plans may be desirable, its overarching goal of preventing recurring issues is of greater concern. MRO uses the webCDMS platform to automate processes for the review, approval, tracking, and certification of mitigation plans, and it participates in efforts across the ERO Enterprise to develop metrics to encourage timely processing of mitigation plans.

As demonstrated in the table below, MRO has made substantial progress in ensuring that older violations have completed mitigation, with 100% of violations discovered from 2007 through 2010 having completed mitigation.

MRO: Status of Mitigating Activity for Violations Discovered from 2007-2013 and Requiring Mitigation as of December 31, 2013[105]

Year of Discovery	% Completed	% in Progress
2013	14.7%	85.3%
2012	58.5%	41.5%
2011	79.5%	20.5%
2010	100.0%	0.0%
2009	100.0%	0.0%
2008	100.0%	0.0%
2007	100.0%	0.0%
Grand Total	**70.4%**	**29.6%**

NERC is working closely with MRO to understand the nature of the violations with open mitigation and ensure that violations are mitigated in a timely manner. Specifically, NERC will work with MRO to understand why just over half of 2012 violations have completed mitigation and less than 15% of 2013 violations have completed mitigation.[106] NERC encourages MRO to continue to seek solutions that will promote reliability and work to ensure that mitigation is completed in a timely manner.

iii. Promoting Reliability through Enforcement Philosophy and Practices

MRO's enforcement philosophy is to ensure that enforcement determinations match its essential purpose: to improve reliability and address risks to reliability. MRO reserves settlements for more complicated matters and encourages investments in systems and people as an offset for proposed penalties. An important tenet of MRO's enforcement philosophy is to use technical experts with the requisite knowledge and experience to assess actual risk posed by individual violations. MRO's enforcement philosophy considers highly effective reliability organizations to be those that prevent uncontrolled cascading outages through disciplined management practices and are accountable for their performance. As a result, registered entities in the MRO region accept responsibility (or "admit") in 90% of all violations.[107]

Similar to the other Regional Entities, MRO worked with registered entities, where appropriate, to accept the completion of certain activities above-and-beyond those required to ensure compliance with one or more Reliability Standards, in lieu of the full monetary penalties

[105] This table reports the percentage of violations discovered from the years 2007 through 2013 with completed or open mitigation. This table excludes dismissed violations and non-U.S. violations.

[106] Although a number of violations from 2011 have open mitigation, most of these violations involve the same registered entity.

[107] JRESA, Appendix 2-C at 13. MRO's Regulatory Philosophy (April 30, 2014) is available at: http://www.midwestreliability.org/01_about_mro/Public%20Awareness/2014/MRO_Regulatory_Philosophy_043014.pdf.

permitted by the NERC *Sanction Guidelines*. MRO states that, during the assessment period, it sought to include above-and-beyond commitments whenever possible. These efforts allow registered entities to allocate their resources to those projects that can increase overall reliability and reduce the likelihood of future noncompliance.

As an example of the type of above-and-beyond commitments made by registered entities in the MRO region, one registered entity committed to the hiring of additional compliance personnel, installation of new alarming systems, replacement of electromechanical relays and communication equipment with microprocessor relays and mirrored bit over fiber communications, and the provision of additional training for entity staff. Another registered entity committed to the following activities: (i) sharing its experience and lessons learned related to compliance with PRC-005-1 with at least three industry peer groups such as the North American Generator Forum and the Mid Continent Compliance Forum; (ii) securing NERC Compliance training from an outside consultant for at least six individuals from its Nuclear Business Unit; (iii) coordinating with and benchmarking the adoption of NERC compliance efforts at two nuclear facilities owned and operated by two different entities (one within the MRO region and one outside the MRO region); and (iv) replacing certain solid state relays with microprocessor relays. In another instance, the registered entity accelerated its replacement schedule for aging assets to include replacement of four additional electro-mechanical relay panels with completely digital, self-diagnostic relays, among other above-and-beyond actions over a three year period. NERC encourages MRO to continue deploying solutions such as these that promote reliability and insight into processes that can manage risk.

d. MRO'S Implementation of Various Aspects of the CMEP

As noted in §II.D.1.a above, NERC conducts ongoing oversight activities to evaluate the effectiveness of each Regional Entity's implementation of the CMEP. These activities include regular reviews and periodic spot checks of specific Regional Entity processes. NERC's oversight activities give NERC an ongoing view into how effectively and efficiently the Regional Entity is executing its enforcement responsibilities. Below is a summary of some of NERC's more recent oversight activities specific to MRO.

With respect to the appropriateness of monetary penalties, MRO undertook several efforts during the assessment period to ensure consistency of remedies within its region. MRO also participated in various initiatives to increase interaction with other Regional Entities, such as through the various Regional Entity working groups. MRO does not review or track all monetary penalties proposed by other Regional Entities. However, MRO reviews penalty determinations for similar violations in the MRO region and other Regional Entities and, as appropriate, discusses proposed penalties with other Regional Entities and NERC. NERC reviews all penalties submitted by MRO for appropriateness and consistency with monetary penalties assessed by MRO and by other Regional Entities for violations of the same Reliability Standards and Requirements occurring under similar facts and circumstances. NERC has found that MRO assesses monetary penalties that are appropriate and consistent with penalties assessed for similar violations.

Based on a spot check, NERC determined that MRO dismisses violations for appropriate reasons and generally includes the required information when issuing letters of dismissal. NERC

identified opportunities where MRO could improve its letters of dismissal, and communicated those opportunities to MRO. By implementing the recommended improvements, MRO can improve the quality of its compliance guidance to registered entities.

As part of its ongoing FFT review processes, NERC reviewed a sample of MRO FFT issues filed or posted during the assessment period to examine MRO's procedures for FFT processing and the application of those procedures to the FFT issues in its caseload. NERC concluded that MRO's process documents for FFT processing are clear, easy-to-follow, and facilitate consistent application. Further, NERC noted that MRO uses a checklist to ensure that it follows its process by tracking all of the steps that must be taken. NERC concluded that MRO generally assessed the risk posed by an issue in light of all relevant facts and ensured that mitigating activities addressed both mitigation of the issue and prevention of reoccurrence. NERC noted several ways that MRO could improve its FFT postings and related documentation to provide additional transparency to its determinations.

e. Conclusion

Based on NERC's review of the factors described above, NERC concludes that MRO has performed as an effective Regional Entity with respect to enforcement activities during the assessment period. In addition, NERC commends MRO for its substantial efforts in the development of RAI. MRO should adopt the recommendations for improvement noted above. In particular, based on MRO's performance in several enforcement processing metrics, MRO should work to identify and implement solutions so that it is better equipped to ensure that violations are processed as quickly as is practicable consistent with the circumstances of each violation. MRO should also adopt the other recommendations for improvement provided as part of NERC's oversight activities.

4. Evaluation of Northeast Power Coordinating Council, Inc.

a. Overview

In the three-year performance assessment, NERC concluded that NPCC was a relatively effective Regional Entity in that it processed and completed identified violations in a timely manner. However, NERC indicated its concern that NPCC may not be identifying all violations that are occurring.[108]

NPCC believes that, during the assessment period, it has built a very cost-effective compliance program through the use of independent contractors. NPCC's level of alleged violations per registered reliability function remains low, but in line with other Regional Entities. NPCC believes its low level of violations per registered reliability function is a product of its thorough outreach and communication with registered entities in its region.[109]

[108] *Three-Year ERO Performance Assessment Report*, Attachment 3 at 19-20.

[109] 2014 JRESA, Appendix 2-B at 3.

During the assessment period, NPCC has increased the number of FTE staff dedicated to enforcement from 2 in 2009 to 4 as of December 31, 2013. Based on NPCC's processing speed and efficiency as measured at the end of the assessment period, NERC views NPCC's enforcement staffing to be sufficient to process the number of violations that it receives.

NPCC ended the assessment period with a Caseload Index that was somewhat better than the ERO Enterprise Caseload Index. NPCC processed all violations that were discovered before 2012, in furtherance of an ERO Enterprise goal. NPCC's caseload now consists of more-recent violations, and NPCC has made progress in ensuring that older violations are mitigated. Finally, NERC has reviewed NPCC's enforcement-related processes as part of its oversight role and found that, while areas for improvement remain, NPCC generally implements those processes in a satisfactory manner.

In addition, NPCC staff have actively participated in the development of RAI. Specifically, NPCC staff have participated in the Aggregation of Minimal Risk Issues and Enforcement Discretion pilot programs and served on the *ERO Self-Report User Guide* and *ERO Enterprise Mitigation Plan Guide* drafting teams. NPCC also participated in several compliance-based programs. In addition, NPCC staff have participated in the process to develop improvements for the compliance and enforcement oversight of MRREs. This participation is vital as the ERO Enterprise shifts toward a risk-based model of compliance and enforcement.

As explained more fully below, based on NPCC's Caseload Index, NPCC's successful processing of its older violations (as facilitated by its effective implementation of streamlined enforcement processing mechanisms), and the results of NERC's oversight activities, NERC concludes that NPCC has performed as an effective Regional Entity with respect to enforcement activities during the assessment period. Going forward, NERC will work with NPCC to ensure that violations are mitigated promptly.

b. Evaluation of Caseload Processing Efficiency

i. The Composition of NPCC's Caseload

During the assessment period, NPCC reported 551 violations to NERC.[110]

Violations for NPCC 2009-2013 by Year Reported to NERC[111]

Year Reported to NERC	Violations Reported
2009	43
2010	99
2011	130

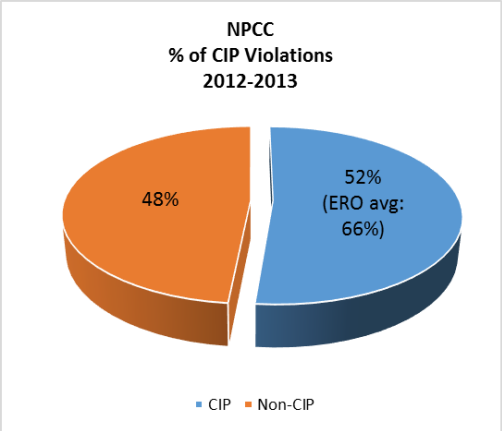
[110] This table reflects U.S. violations only. When including Canadian violations, NPCC reported 670 violations from 2009 through 2013.

[111] For an explanation of the methodology used to calculate the data in this table and throughout this §II.D, *see supra* n. 766.

2012	213
2013	66
Total	**551**

As noted in the table above, NPCC reported the highest number of violations in 2012, with a substantial decline in 2013. In the years 2012 and 2013, violations of CIP Reliability Standards represented 52% of total violations; this is a lower percentage than the ERO Enterprise average of 66%.

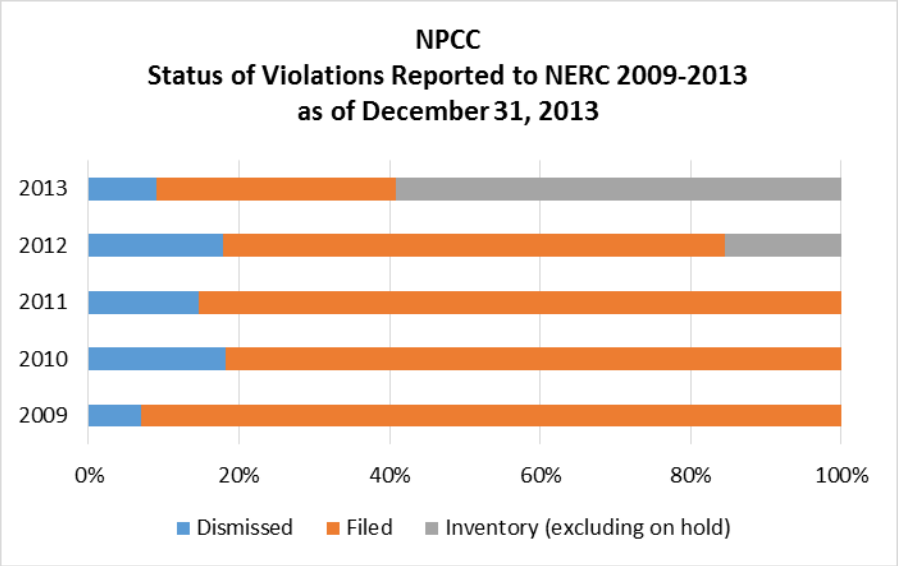
Type of Violations Reported to NERC by NPCC, 2012-2013



Over the assessment period, CIP violations made up 54.6% of total violations in NPCC, compared to the ERO Enterprise average of 59.4%. Approximately 70% of the CIP violations were self-identified. NERC will work with NPCC to understand what factors may have caused NPCC to have a lower percentage of CIP violations than other Regional Entities in 2012-2013.

Of the total violations reported to NERC during the assessment period, approximately 72 violations, or 13%, remained to be processed as of December 31, 2013 (excluding violations that are held by appeal, a court, or a regulator). As demonstrated in the table below, NPCC has processed all violations that were reported to NERC in 2009, 2010, and 2011. NPCC has processed approximately 85% of violations reported to NERC in 2012.

Status of Violations Reported to NERC 2009-2013 for NPCC



NPCC processed approximately 41% of violations that it reported to NERC in 2013. This is consistent with the ERO 2013 processing rate of 39%. Approximately 54% of the violations available for processing in NPCC's inventory consist of violations reported to NERC in 2013. This is lower than the overall ERO Enterprise average of 67%.

ii. Caseload Index

The Caseload Index for NPCC is 6.7 months as of December 31, 2013. This is consistent with the ERO Enterprise Caseload Index of approximately 6.5 months.

In light of NPCC's Caseload Index and as reflected in the general characteristics of its caseload (i.e., NPCC's caseload consists entirely of violations reported to NERC in 2012 and 2013), NPCC continued to process violations in a timely manner during the assessment period.

iii. Efforts to Reduce Older Caseload

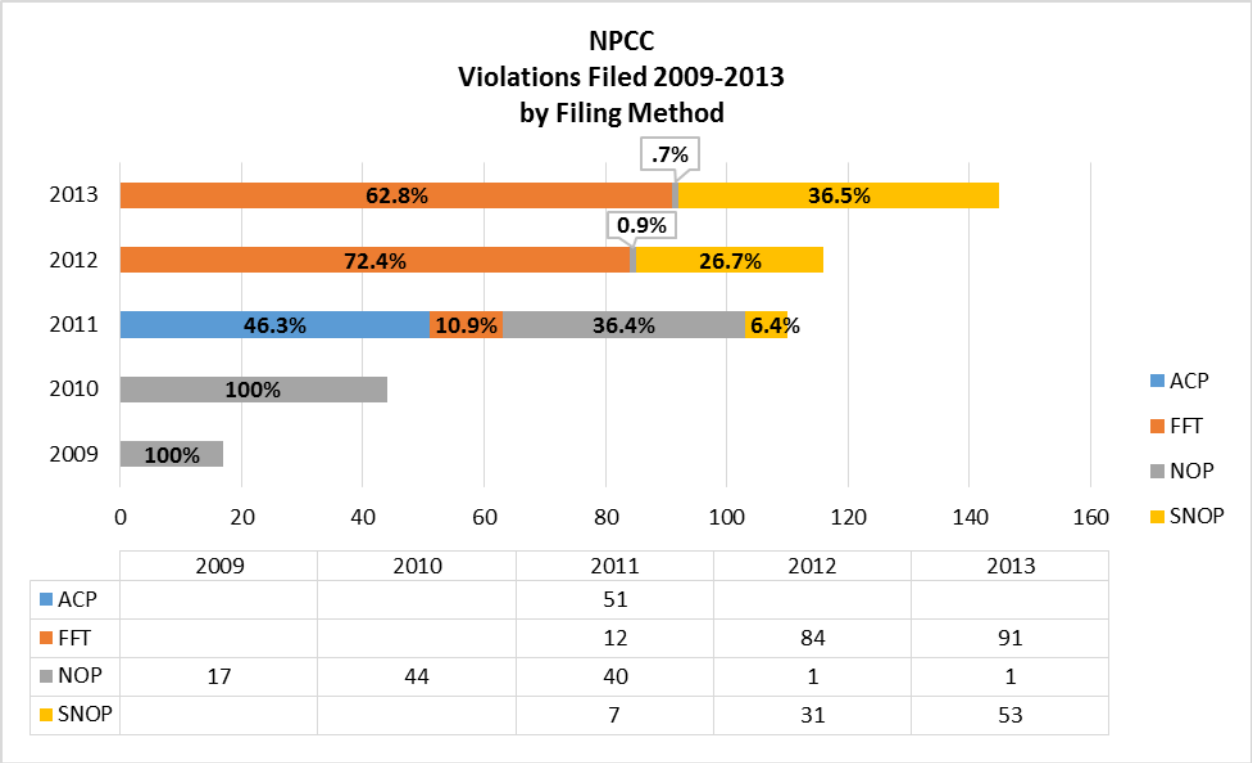
In 2013, NPCC completed processing of all pre-2012 violations. NERC commends NPCC for its responsiveness and efforts to achieve this important ERO Enterprise goal. Based on the current composition of its inventory of violations available to be processed, NPCC is well-positioned to achieve the goal of ensuring that violations are processed before reaching 24 months in age.

iv. Implementation of Streamlined Enforcement Processing Mechanisms

NPCC effectively used streamlined processing mechanisms to process a substantial portion of its caseload during the assessment period. In 2011, following the implementation of the

streamlined enforcement processing mechanisms, NPCC filed 110 violations – more than the previous two years combined.

Violations Filed per Year by Filing Method for NPCC, 2009-2013



	2009	2010	2011	2012	2013
ACP			51		
FFT			12	84	91
NOP	17	44	40	1	1
SNOP			7	31	53

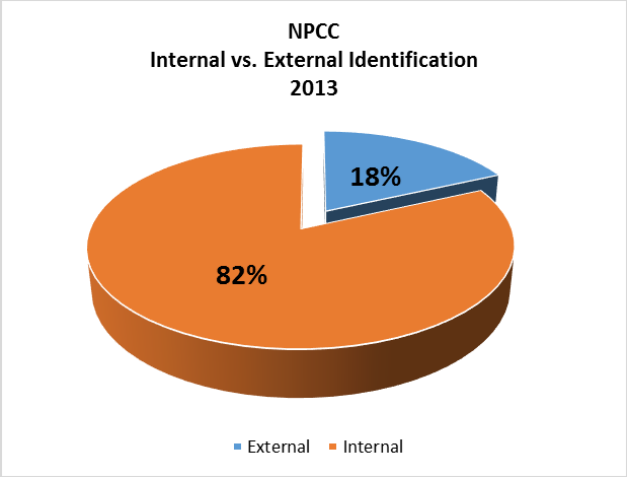
By 2012, NPCC filed nearly all of its violations using either SNOP or FFT. NPCC reported that it discusses the application of FFT and SNOP with other Regional Entity representatives to ensure consistency. NERC expects that NPCC will continue to reserve the NOP format for violations that require it and to take advantage of further process refinements available under RAI. Additional information regarding NPCC's application of FFT is presented later in this assessment.

c. Improving Reliability

i. Encouraging Internal Discovery of Violations

In 2013, violations discovered by registered entities through internal mechanisms comprised 82% of total violations in the NPCC region. This is somewhat higher than the ERO Enterprise average of 73%.

Percentage of Violations by Method of Identification for NPCC in 2013



ii. Ensuring the Timely Mitigation of Violations

NPCC has enhanced its self-report form to include data fields that allow registered entities to supply details of mitigation plans or mitigating activities when submitting a self-report. NPCC believes that use of these new data fields has resulted in earlier implementation of mitigation, thereby promoting improved reliability. NPCC works closely with each registered entity to process mitigation plans in a timely manner.

As demonstrated in the table below, NPCC has made substantial progress in ensuring that pre-2012 violations have been mitigated.

NPCC: Status of Mitigating Activity for Violations Discovered from 2007-2013 and Requiring Mitigation as of December 31, 2013[112]

Year of Discovery	% Completed	% in Progress
2013	37.5%	62.5%
2012	86.3%	13.7%
2011	100.0%	0.0%
2010	100.0%	0.0%
2009	100.0%	0.0%
2008	100.0%	0.0%
2007	100.0%	0.0%
Grand Total	**89.0%**	**11.0%**

[112] This table reports the percentage of violations discovered from the years 2007 through 2013 with completed or open mitigation. This table excludes dismissed violations and non-U.S. violations.

Approximately 22 violations from 2012 remain to be mitigated, along with 62.5% of violations from 2013. NERC is working closely with NPCC to ensure that violations are mitigated in a timely manner.

iii. Promoting Reliability through Enforcement Philosophy and Practices

NPCC's enforcement philosophy is to develop relationships with the registered entities in its region to: (1) educate them on the aspects of the CMEP and its implementation; (2) inform them of the changes to the enforcement process during biannual workshops; and (3) promote RAI.

In its settlement processes, NPCC has worked with registered entities, where appropriate, to accept the completion of certain activities above-and-beyond those required to ensure compliance with one or more Reliability Standards in lieu of the full monetary penalties permitted by the NERC *Sanction Guidelines*. These efforts allow registered entities to allocate their resources to those projects that can increase overall reliability and reduce the likelihood of future noncompliance.

As an example of above-and-beyond activities, one registered entity within the NPCC region committed to establish an enterprise-wide compliance program, with resources dedicated to implementing that program. Another registered entity committed to implement software systems (rather than manual record-keeping) to track protection system devices and their associated maintenance intervals. On one occasion, a registered entity committed to implement Light Detection and Ranging (LiDAR)-based Power Line Systems as a supplemental tool to identify site conditions. NERC encourages NPCC to continue deploying solutions such as these that promote reliability and insight into processes that can manage risk.

d. NPCC'S Implementation of Various Aspects of the CMEP

As noted in §II.D.1.a above, NERC conducts ongoing oversight activities to evaluate the effectiveness of each Regional Entity's implementation of the CMEP. These activities include regular reviews and periodic spot checks of specific Regional Entity processes. NERC's oversight activities give NERC an ongoing view into how effectively and efficiently the Regional Entity is executing its enforcement responsibilities. Below is a summary of some of NERC's more recent oversight activities specific to NPCC.

NPCC reported that, in addition to using the NERC *Sanction Guidelines* as a guide for assessing monetary penalties, NPCC reviews the monthly enforcement filings. Specifically, NPCC compares the penalties that other Regional Entities assess for violations of Reliability Standards and Requirements and contacts other Regional Entities to discuss penalties where appropriate. NERC reviews all penalties submitted by NPCC for appropriateness and consistency with monetary penalties assessed by NPCC and other Regional Entities for violations of the same Reliability Standards and Requirements occurring under similar facts and circumstances. NERC has found that NPCC assesses monetary penalties that are appropriate and consistent with penalties assessed for similar violations.

Based on a spot check, NERC determined that NPCC generally dismisses violations for appropriate reasons, and generally includes the required information when issuing letters of dismissal. NERC identified opportunities for NPCC to improve its letters of dismissal and communicated those opportunities to NPCC. By implementing the recommended improvements, NPCC can improve the quality and clarity of its compliance guidance to registered entities.

As part of its ongoing FFT review processes, NERC reviewed a sample of NPCC FFT issues filed or posted during the assessment period to examine NPCC's procedures for FFT processing and the application of those procedures to the FFT issues in its caseload. Following its review, NERC concluded that NPCC maintains process documents governing the application of the FFT process. NERC noted that NPCC ensures that mitigating activity is completed. NPCC's issue descriptions are generally adequate to describe the issue. NERC noted several ways that NPCC could improve its FFT postings and related documentation to provide additional transparency to its determinations.

e. Conclusion

Based on NERC's review of the factors described above, NERC concludes that NPCC has performed as an effective Regional Entity with respect to enforcement activities during the assessment period. NPCC should adopt the recommendations for improvement provided as part of NERC's oversight activities.

5. Evaluation of ReliabilityFirst Corporation

a. Overview

In the three-year performance assessment, NERC concluded that, consistent with the overall findings for the ERO Enterprise, ReliabilityFirst needed to improve its efficiency with respect to conducting enforcement activities.[113] ReliabilityFirst has taken several steps to increase its efficiency with respect to conducting enforcement activities during the assessment period, including setting internal violation processing goals that are tied to corporate goals and training enforcement staff on how to become more efficient in their fact-gathering efforts. In 2013, ReliabilityFirst implemented a practice of consolidating multiple violations of the same standard with similar facts into a single docket number and consolidating multiple docket numbers with similar violations into a single settlement agreement or FFT. ReliabilityFirst believes this practice furthers its approach to resolving violations, an approach which it described as "holistic." ReliabilityFirst has also focused its efforts on those violations that pose the greatest risk to reliability and expedited its processing of lesser-risk violations through the FFT process.[114]

During the assessment period, ReliabilityFirst increased the number of FTE staff dedicated to enforcement from 8 in 2009 to 12 as of December 31, 2013.

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[113] *Three-Year ERO Performance Assessment Report*, Attachment 3 at 21-22. NERC also noted that an independent audit of ReliabilityFirst's compliance program found no material deficiencies.

[114] 2014 JRESA, Appendix 2-B at 6.

NERC recognizes the progress ReliabilityFirst has made in enforcement processing during the assessment period. ReliabilityFirst made significant progress in reducing the number of open violations, despite substantial increases in new violations during the assessment period. Moreover, during the assessment period, ReliabilityFirst worked with and resolved a number of complex matters concerning registered entities with significant BPS operations. When resolving each of these complex matters, ReliabilityFirst encouraged registered entities to implement actions above and beyond baseline compliance to improve the reliability and security of the BPS. Examples of these above-and-beyond actions are presented below.

NERC also recognizes that ReliabilityFirst often takes the lead in settlement negotiations to resolve violations from MRREs. ReliabilityFirst has routinely demonstrated a commitment to use the enforcement process to promote the reliability of the BPS. Further, NERC has reviewed ReliabilityFirst's enforcement-related processes as part of its oversight role and found that, while areas for improvement remain, ReliabilityFirst generally implements those processes in a satisfactory manner. However, ReliabilityFirst ended the assessment period with a higher-than-average Caseload Index. In addition, while ReliabilityFirst made substantial strides in reducing the portion of its caseload consisting of violations dating to before 2012, ReliabilityFirst had a number of older violations in its inventory that needed to be mitigated and processed by the end of the assessment period. As is discussed in more detail below, ReliabilityFirst is working closely with the registered entities to complete mitigation and processing of these older violations.

NERC recognizes the contributions ReliabilityFirst staff have made in the development of RAI and the related enforcement pilot programs. ReliabilityFirst has taken a leadership role in the conceptualization, development, testing, and integration of several programs, and a member of ReliabilityFirst's staff led the multi-region working group on enforcement activities during the assessment period. ReliabilityFirst staff participated in the Enforcement Discretion pilot program and served on the *ERO Self-Report User Guide* and *ERO Enterprise Mitigation Plan Guide* drafting teams. ReliabilityFirst staff have also participated in the process to develop improvements for the compliance and enforcement oversight of MRREs. ReliabilityFirst also maintained the sole MRRE log during the Aggregation of Minimal Risk Issues pilot program. This participation is vital as the ERO Enterprise shifts toward a risk-based model of compliance and enforcement.

In light of all the relevant factors, which are explained more fully below, NERC concludes that ReliabilityFirst has performed as an effective Regional Entity with respect to enforcement activities during the assessment period. However, ReliabilityFirst should consider exploring and implementing solutions that will assist ReliabilityFirst in processing the substantial number of violations that it receives on a yearly basis while meeting the performance objectives of the ERO Enterprise.

b. Evaluation of Caseload Processing Efficiency

i. The Composition of ReliabilityFirst's Caseload

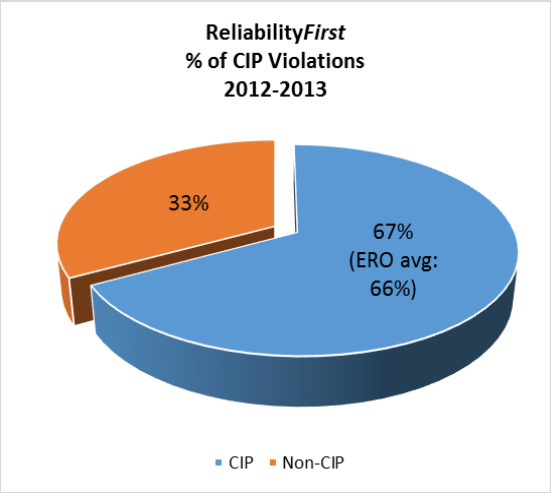
During the assessment period, ReliabilityFirst reported 1,902 violations to NERC, the second highest number among the Regional Entities.

Violations for ReliabilityFirst 2009-2013 by Year Reported to NERC[115]

Year Reported to NERC	Violations Reported
2009	123
2010	469
2011	565
2012	505
2013	240
Total	**1902**

As shown in the table above, ReliabilityFirst reported the highest number of violations in 2011, with a gradual decrease in 2012 and a substantial decrease in 2013. Approximately two-thirds of the violations in 2011 were of the CIP Reliability Standards. In the years 2012 and 2013, violations of CIP Reliability Standards represented 67% of total violations; this percentage is consistent with the ERO Enterprise average of 66%.

Type of Violations Reported to NERC by ReliabilityFirst, 2012-2013

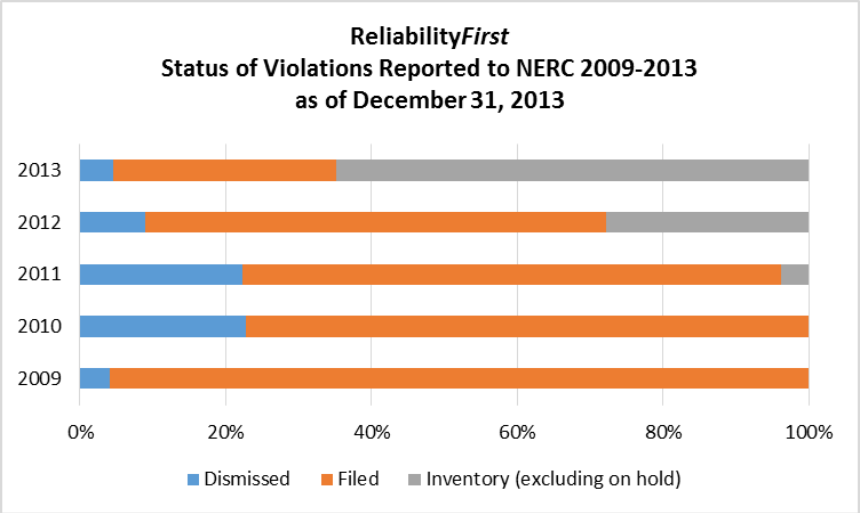


Approximately 76% of the CIP violations were discovered through internal means.

Of the total violations reported to NERC during the assessment period, approximately 316 violations, or approximately 17%, remained to be processed as of December 31, 2013 (excluding violations that are held by appeal, a court, or a regulator). As demonstrated in the table below, ReliabilityFirst has processed all violations that were reported to NERC in 2009 and 2010 (excluding on hold violations). ReliabilityFirst has processed approximately 96% of violations reported to NERC in 2011 (excluding on hold violations), and approximately 72% of violations reported to NERC in 2012.

[115] For an explanation of the methodology used to calculate the data in this table and throughout this §II.D, *see supra* n. 766.

Status of Violations Reported to NERC 2009-2013 for ReliabilityFirst



ReliabilityFirst processed approximately 35% of violations reported to NERC in 2013 (excluding on hold violations). This is slightly lower than the ERO 2013 processing rate of 39%. Further, the percentage of ReliabilityFirst's caseload consisting of violations reported to NERC in 2013 (approximately 49%), is substantially lower than the overall ERO Enterprise average of 67%.

ii. Caseload Index

The Caseload Index for ReliabilityFirst was 9.8 months as of December 31, 2013. Although this is higher than the ERO Enterprise Caseload Index of approximately 6.5 months, NERC notes that ReliabilityFirst performed well, relative to the ERO Enterprise average, for the majority of the assessment period. NERC also recognizes that in 2014, ReliabilityFirst has resolved a significant number of the current set of cases and is on track to resolve the remaining cases that are responsible for the higher-than-average Caseload Index at the end of the assessment period. The majority of these cases are large, multi-regional matters.

iii. Efforts to Reduce Older Caseload

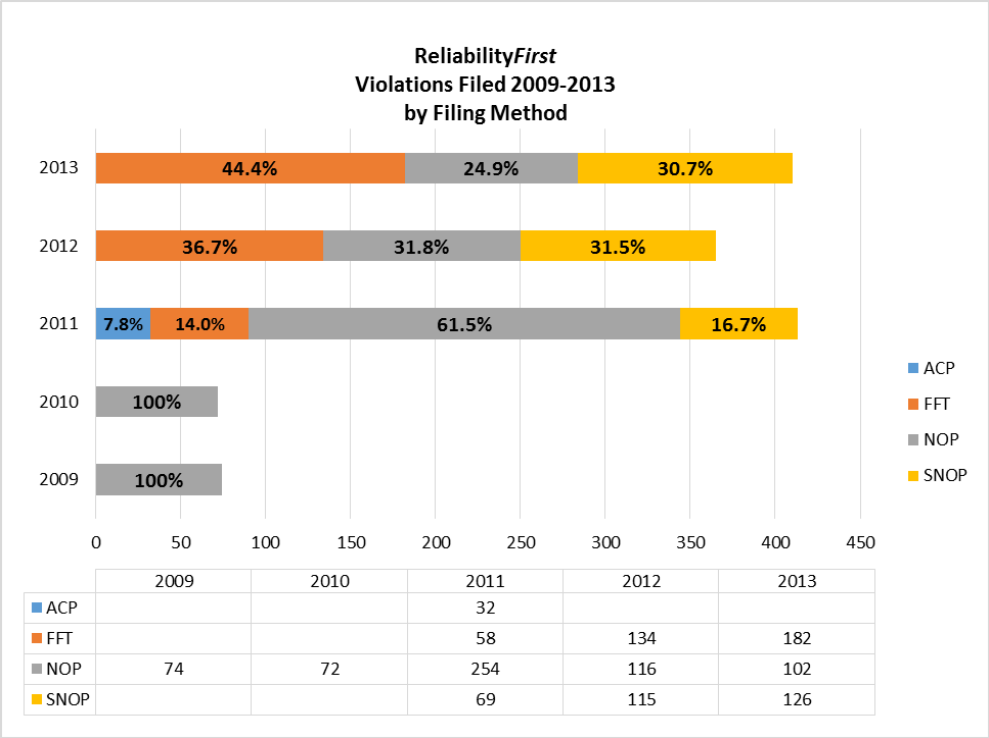
In 2013, ReliabilityFirst reduced the portion of its caseload consisting of violations dating to before 2012 by 88%. NERC commends ReliabilityFirst for its responsiveness and efforts to achieve this important ERO Enterprise goal. ReliabilityFirst reported that its remaining inventory consisted of particularly broad and complex violations that are part of large settlement agreements in the process of being negotiated. ReliabilityFirst also reported that it has been closely monitoring and working with the registered entities to ensure effective and holistic mitigation for these older, more complex violations.

NERC will continue to work with ReliabilityFirst to prioritize the processing of these violations and other older violations so that ReliabilityFirst may achieve the goal of ensuring that violations are processed before reaching 24 months in age.

iv. Implementation of Streamlined Enforcement Processing Mechanisms

ReliabilityFirst effectively used streamlined enforcement processing mechanisms to process a substantial portion of its caseload during the assessment period. In 2011, following the implementation of the streamlined enforcement processing mechanisms, ReliabilityFirst filed 413 violations – more than two-and-a-half times the total of the previous two years combined.

Violations Filed per Year by Filing Method for ReliabilityFirst, 2009-2013



	2009	2010	2011	2012	2013
ACP			32		
FFT			58	134	182
NOP	74	72	254	116	102
SNOP			69	115	126

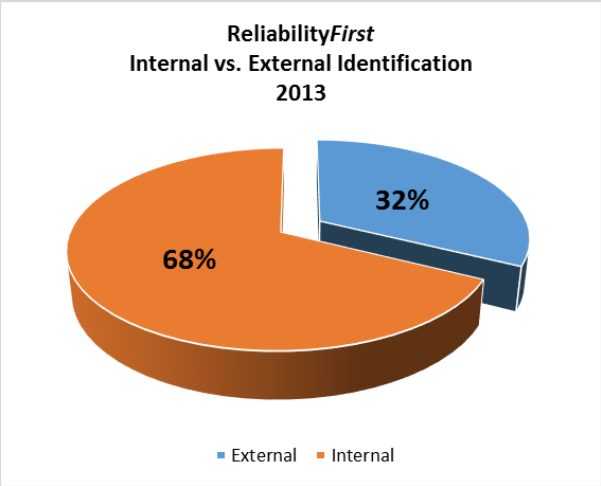
ReliabilityFirst uses the FFT process for minimal or moderate risk violations where it seeks to encourage certain entity behavior (or conversely, where there is there is an absence of behavior that ReliabilityFirst wishes to discourage). ReliabilityFirst prepares NOPs where there are important mitigating actions, above-and-beyond commitments, or reliability concerns that may not be adequately presented in the SNOP format. ReliabilityFirst also confers with other Regional Entities through an enforcement activities working group to ensure that each of the Regional Entities develops consistent documentation for the FFT process and makes consistent risk determinations when deciding whether to grant FFT or SNOP treatment for a violation. NERC expects that ReliabilityFirst will continue to take advantage of further process refinements available under RAI. Additional information regarding ReliabilityFirst's implementation of FFT is presented later in this assessment.

c. Improving Reliability

i. Encouraging Internal Discovery of Violations

In 2013, violations discovered by registered entities through internal mechanisms comprised 68% of total violations in the ReliabilityFirst region. This is slightly lower than the ERO Enterprise average of 73%.

Percentage of Violations by Method of Identification for ReliabilityFirst in 2013



ii. Ensuring the Timely Mitigation of Violations

ReliabilityFirst reported that it encourages the prompt submission of mitigation plans in its notices of possible violation, in compliance audit exit briefings, and as part of its enforcement process. ReliabilityFirst considers the prompt submission of mitigation plans when making its penalty determinations and the prompt identification of mitigating activities in its determination of FFT eligibility. ReliabilityFirst has processes in place for the review, acceptance, and verification of mitigation plans, and it has tracking systems in place to help ensure that mitigation plans are submitted, reviewed, and accepted in a timely manner. ReliabilityFirst does not require formal mitigation plans for some minimal and moderate risk violations, but rather requires submission of a formal mitigation plan based on the risk posed by each violation. ReliabilityFirst sends notifications to registered entities when necessary to ensure that they submit mitigation plans promptly and meet associated deadlines. Acceptance and verification of mitigation plans passes through a multi-layer review and approval process. During this process, ReliabilityFirst works closely with the applicable registered entity to ensure that the proposed mitigating activities address the underlying cause of the violation, the time to complete the mitigating activities is reasonable, and effective steps are taken to prevent reoccurrence of violations.

NERC is working closely with ReliabilityFirst to ensure that violations are mitigated in a timely manner. As demonstrated in the table below, ReliabilityFirst has made notable progress in ensuring that older violations have been mitigated, with 100% of violations discovered from 2007-

2009, 98.1% of violations discovered in 2010, and 89.1% of violations discovered in 2011 having completed mitigation.

ReliabilityFirst: Status of Mitigating Activity for Violations Discovered from 2007-2013 and Requiring Mitigation as of December 31, 2013[116]

Year of Discovery	% Completed	% in Progress
2013	24.5%	75.5%
2012	68.3%	31.7%
2011	89.1%	10.9%
2010	98.1%	1.9%
2009	100.0%	0.0%
2008	100.0%	0.0%
2007	100.0%	0.0%
Grand Total	**79.6%**	**20.4%**

ReliabilityFirst reported that it is working closely with registered entities to ensure the completion of effective mitigating activities for these violations. NERC will continue to work closely with ReliabilityFirst to ensure that violations are mitigated in a timely manner.

iii. Promoting Reliability through Enforcement Philosophy and Practices

ReliabilityFirst has taken a proactive approach to developing a detailed enforcement philosophy. ReliabilityFirst's enforcement philosophy consists of several overarching themes governing enforcement and a series of philosophies governing particular aspects of the enforcement process. ReliabilityFirst's philosophy is to not see the enforcement process as adversarial, but rather as an opportunity to work collaboratively with registered entities to craft forward-thinking resolutions designed to enhance reliability. ReliabilityFirst's philosophy is to use the enforcement process as a tool to shape and encourage desired registered entity behavior, and to only assess monetary penalties where the penalty is appropriate to encourage or discourage behavior and where the justification is supported by sound, consistent, and risk-based reasoning. ReliabilityFirst encourages the development of strong internal controls and other steps taken to improve compliance.

In its settlement processes, ReliabilityFirst has worked with registered entities, where appropriate, to accept the completion of certain activities above-and-beyond those required to ensure compliance with one or more Reliability Standards in lieu of the full monetary penalties permitted by the NERC *Sanction Guidelines*. These efforts allow registered entities to allocate their resources to those projects that can increase overall reliability and reduce the likelihood of future noncompliance.

[116] This table reports the percentage of violations discovered from the years 2007 through 2013 with completed or open mitigation. This table excludes dismissed violations.

ReliabilityFirst has worked with registered entities to include commitments in their mitigation plans going beyond those actions necessary to mitigate the underlying violations. Several notable examples are presented here. One registered entity committed to an aggressive timeline for the completion of mitigating actions, including completing certain activities faster than required by NERC guidance. To resolve a violation involving facility ratings, one registered entity committed to perform a broad review and verification of system components, to implement a new ratings software application, and to use LiDAR-based Power Line Systems – Computer Aided Design and Drafting (PLS-CADD) modeling as a supplemental tool to identify site conditions that may indicate potential ratings issues. One registered entity committed to perform an ongoing risk analysis of its cybersecurity policies and procedures using a Failure Modes Effects Analysis tool (a continuous improvement tool to improve the quality of process outputs by identifying and removing the cause of defects and errors and minimizing variability in processes). Another registered entity committed to conduct an evaluation of the U.S. Department of Energy Electricity Subsector Cybersecurity Capability Maturity Model (ES-C2M2) and create and implement an action plan with the goal of increasing the entity's maturity indicator level in domains related to the CIP Reliability Standards. ReliabilityFirst has also imposed the non-monetary sanction of conducting an unscheduled audit before the next six-year scheduled audit to ensure that a registered entity's implementation of a new compliance program improved and better positioned the registered entity's compliance posture prospectively. NERC encourages ReliabilityFirst to continue deploying solutions such as these that promote reliability and insight into processes that can manage risk.

d. ReliabilityFirst's Implementation of Various Aspects of the CMEP

As noted in §II.D.1.a above, NERC conducts ongoing oversight activities to evaluate the effectiveness of each Regional Entity's implementation of the CMEP. These activities include regular reviews and periodic spot checks of specific Regional Entity processes. NERC's oversight activities give NERC an ongoing view into how effectively and efficiently the Regional Entity is executing its enforcement responsibilities. Below is a summary of some of NERC's more recent oversight activities specific to ReliabilityFirst.

With respect to assessing monetary penalties, ReliabilityFirst reported that it has implemented a multi-step internal process for making penalty determinations. First, an assigned case manager makes all penalty recommendations (subject to senior executive review and approval) for his or her assigned registered entities, including the application of the adjustment factors set forth in the NERC *Sanction Guidelines*. Second, ReliabilityFirst has implemented what it calls the "Risk-Harm" process, whereby technical experts answer a series of questions about the risk and harm posed by each violation using a common scale which results in a quantified risk assessment for each violation. Third, ReliabilityFirst analyzes the risk assessment produced from the Risk-Harm process and checks to ensure that the penalty is consistent with the risk posed by the violation. Fourth, ReliabilityFirst looks at previously assessed penalties for comparable violations in the ReliabilityFirst region and in other regions, to ensure the internal and external consistency of its penalties. Finally, ReliabilityFirst requires senior management approval for each settlement agreement or Notice of Alleged Violation and Penalty, to ensure that the penalty is consistent with the risk posed by the violations at issue and is consistent with the enforcement philosophy it wishes to convey to other entities in the region. NERC reviews all penalties

submitted by ReliabilityFirst for appropriateness and consistency with monetary penalties assessed by ReliabilityFirst and other Regional Entities for violations of the same Reliability Standards and requirements occurring under similar facts and circumstances. NERC has found that ReliabilityFirst assesses monetary penalties that are appropriate and consistent with penalties assessed for similar violations.

Based on a spot check, NERC determined that ReliabilityFirst dismisses violations for appropriate reasons and generally includes the required information when issuing letters of dismissal. NERC identified opportunities for ReliabilityFirst to improve its letters of dismissal and communicated those opportunities to ReliabilityFirst. By implementing the recommended improvements, ReliabilityFirst can improve the quality of its compliance guidance to registered entities.

As part of its ongoing FFT review processes, NERC reviewed a sample of ReliabilityFirst FFT issues filed or posted during the assessment period to examine ReliabilityFirst's procedures for FFT processing and the application of those procedures to the FFT issues in its caseload. Following its review, NERC concluded that ReliabilityFirst has clear FFT processes that follow the directives, principles, and processes of the NERC guidance and the directives issued by the Commission regarding FFTs. NERC found that ReliabilityFirst applies its processes consistently. NERC noted several ways that ReliabilityFirst could improve its FFT postings and related documentation to provide additional transparency to its determinations.

e. Conclusion

Based on NERC's review of the factors described above, NERC concludes that ReliabilityFirst has performed as an effective Regional Entity with respect to enforcement activities during the assessment period. ReliabilityFirst should adopt the recommendations for improvement noted above and the recommendations provided as part of NERC's oversight activities. In particular, based on ReliabilityFirst's recent performance in several enforcement processing metrics, ReliabilityFirst is encouraged to continue to identify and implement solutions so that it is better equipped to ensure that violations are processed as quickly as practicable consistent with the circumstances of each violation.

6. Evaluation of SERC Reliability Corporation

a. Overview

In the three-year performance assessment, NERC concluded that SERC was an effective Regional Entity.[117] Consistent with the overall findings for the ERO, NERC noted a need to improve the efficiency of enforcement processes. During the assessment period, SERC made a number of organizational and process improvements to streamline its enforcement process and elevate enforcement within the SERC organizational structure.[118] In particular, SERC has expanded its CIP capabilities based on the increase of CIP violations reported to the region.

[117] *Three-Year ERO Performance Assessment Report*, Attachment 3 at 26.

[118] 2014 JRESA, Appendix 2-B at 5.

During the assessment period, SERC has increased the number of FTE staff dedicated to enforcement from 4.25 FTE in 2009 to 7 FTE as of December 31, 2013. Based on SERC's recent improvements in its processing speed and efficiency (as measured at the end of the assessment period), NERC views SERC's enforcement staffing to be sufficient to process the number of violations that it receives.

SERC ended the assessment period with a Caseload Index that was notably better than the ERO Enterprise Caseload Index. SERC processed a substantial number of violations discovered before 2012 in furtherance of an ERO Enterprise goal and in so doing, improved its performance and shifted the composition of its caseload to newer violations. NERC has reviewed SERC's enforcement-related processes as part of its oversight role and found that, while areas for improvement remain, SERC generally implements these processes in a satisfactory manner.

In addition, SERC staff have actively participated in the development of RAI. SERC staff have participated in the Aggregation of Minimal Risk Issues and Enforcement Discretion pilot programs, and have provided input and feedback during the *ERO Self-Report User Guide* and *ERO Enterprise Mitigation Plan Guide* development processes. In addition, SERC staff have participated in the process to develop improvements for the compliance and enforcement oversight of MRREs. This participation is vital as the ERO Enterprise shifts toward a risk-based model of compliance and enforcement.

As explained more fully below, NERC concludes that SERC has performed as an effective Regional Entity with respect to enforcement activities during the assessment period. However, work remains to be done to ensure that violations are mitigated in a timely manner. Going forward, NERC will work with SERC to ensure that violations are mitigated promptly, with an added emphasis on ensuring the completion of mitigation for older violations.

b. Evaluation of Caseload Processing Efficiency

i. The Composition of SERC's Caseload

During the assessment period, SERC reported 1,393 violations to NERC.

Violations for SERC 2009-2013 by Year Reported to NERC[119]

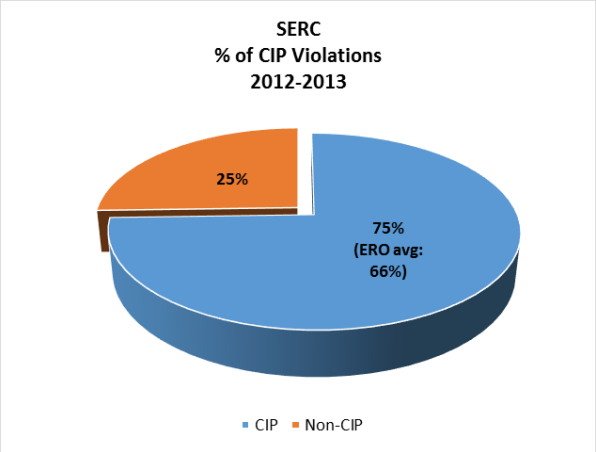
Year Reported to NERC	Violations Reported
2009	187
2010	312
2011	309
2012	300
2013	285

[119] For an explanation of the methodology used to calculate the data in this table and throughout this §II.D, *see supra* n. 76.

Total	**1393**

As shown in the table above, SERC reported a fairly steady number of violations from 2010-2013. In the years 2012 and 2013, violations of CIP Reliability Standards represented a higher percentage (75%) of total violations in the SERC region than the ERO Enterprise as a whole.

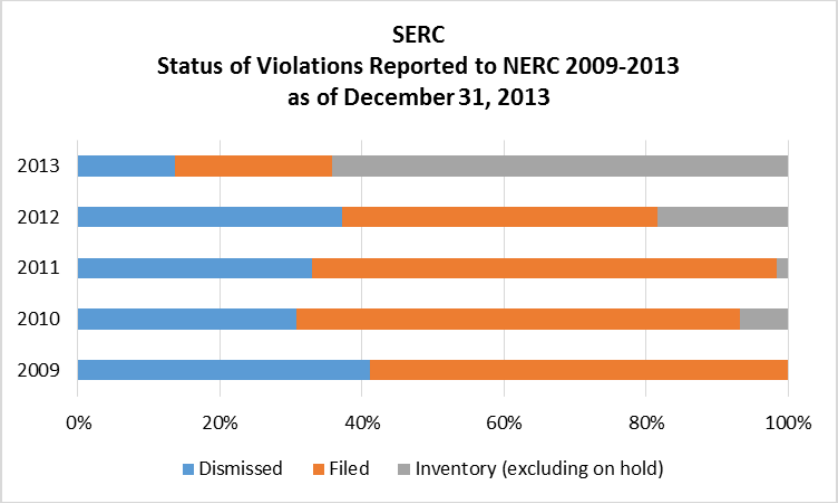
Type of Violations Reported to NERC by SERC, 2012-2013



Over two-thirds of CIP violations received from SERC in 2012 and 2013 were self-identified. SERC's recent expansion of its CIP capabilities should assist SERC in ensuring the timely evaluation and processing of the CIP violations it has received as well as the CIP violations it is likely to receive in the future.

Of the total violations reported by SERC to NERC during the assessment period, approximately 264 violations, or 19%, remained to be processed as of December 31, 2013 (excluding violations that are held by appeal, a court, or a regulator). As demonstrated in the table below, SERC has processed all violations reported to NERC in 2009, 93% of violations reported to NERC in 2010, 98% of violations reported to NERC in 2011, and 82% of violations reported to NERC in 2012 (excluding on hold violations).

Status of Violations Reported to NERC 2009-2013 for SERC



SERC processed approximately 36% of violations it reported to NERC in 2013. This is slightly lower than the ERO 2013 processing rate of 39%. However, violations reported to NERC in 2013 represent approximately 69% of the violations available for processing in SERC's caseload, which is consistent with the overall ERO Enterprise average of 67%.

ii. Caseload Index

The Caseload Index for SERC is 5.1 months as of December 31, 2013. This is better than the ERO Enterprise Caseload Index of approximately 6.5 months and represents a significant improvement in SERC's performance from earlier in the assessment period.

Through 2013, SERC improved its pace of enforcement processing in a dedicated effort to process its older violations. SERC reduced the average age of violations in its inventory by approximately three months from the end of the first quarter of 2013 to the end of 2013. SERC's processing efforts are reflected in the Caseload Index and the other informational measures described in this assessment.

iii. Efforts to Reduce Older Caseload

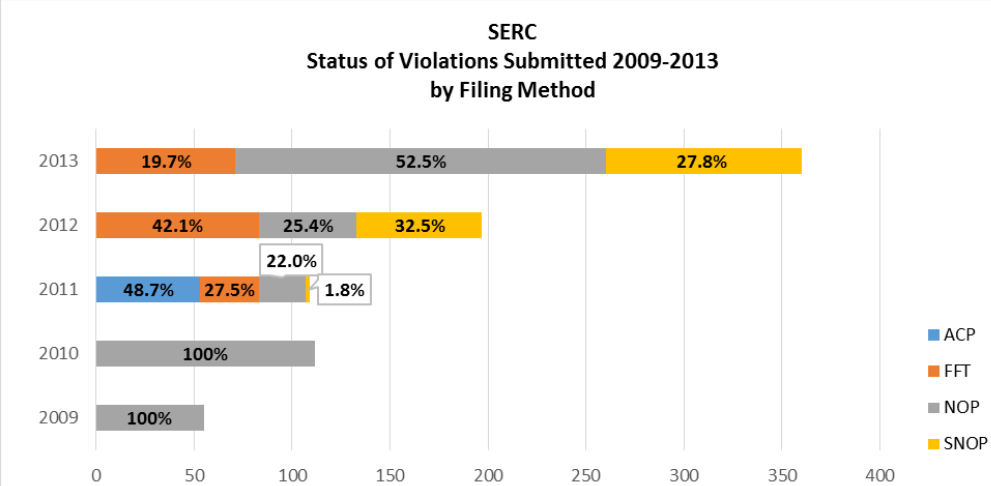
In 2013, SERC reduced its pre-2012 caseload by 92%. Over 90% of these pre-2012 violations were of the CIP Reliability Standards. NERC commends SERC for its responsiveness and efforts to achieve this important ERO Enterprise goal. SERC's remaining pre-2012 violations were in the settlement process or scheduled for processing in early 2014. NERC will work with SERC to ensure that these older violations are resolved and that future accumulations of older violations in the SERC region does not occur.

Based on the current composition of its inventory of violations available to be processed and its recent success in processing its older violations, SERC is positioned to achieve the ERO Enterprise goal of ensuring that violations are processed before reaching 24 months in age.

iv. Implementation of Streamlined Enforcement Processing Mechanisms

SERC believes that its processing of violations has improved because of increased resources and improved tools such as FFT and the SNOP filing mechanisms.[120] As demonstrated in the table below, SERC effectively used streamlined enforcement processing mechanisms to process a substantial portion of its caseload during the assessment period. In 2010, SERC filed an exceptionally high number of violations using the NOP format; in subsequent years, it used the streamlined enforcement processing mechanisms to file 50% or more of violations. In 2013, SERC had a higher percentage of violations processed as an NOP than most Regional Entities, based in large part on SERC's efforts to reduce the number of older, higher-risk CIP violations in its inventory.

Violations Filed per Year by Filing Method for SERC, 2009-2013



	2009	2010	2011	2012	2013
ACP			53		
FFT			30	83	71
NOP	55	112	24	50	189
SNOP			2	64	100

SERC generally uses the FFT process for minimal risk issues, the SNOP process for minimal and moderate risk issues and medium-scale compliance failures, and the NOP process for serious risk issues or large-scale compliance failures. SERC reviews previously-filed violations by SERC and other Regional Entities as part of its process for determining the appropriate enforcement processing mechanism. NERC expects that SERC will continue to reserve the NOP format for violations that require it and take advantage of further process refinements available under RAI. Additional information regarding SERC's implementation of FFT is presented later in this assessment.

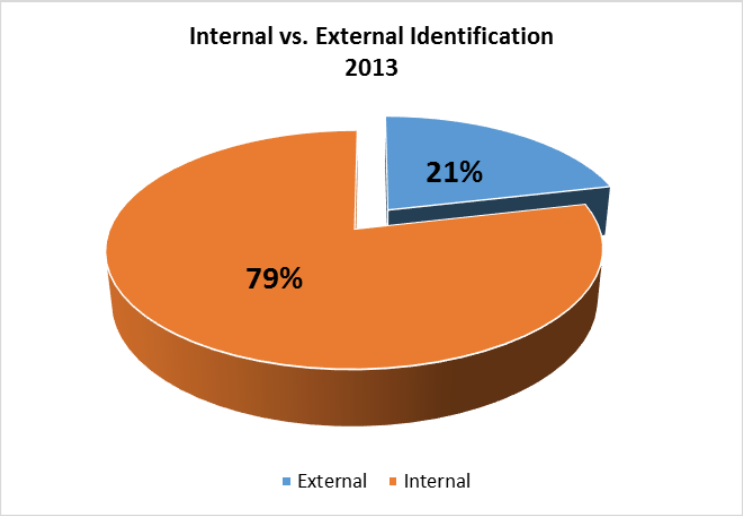
[120] 2014 JRESA, Appendix 2-C at 24.

c. Improving Reliability

i. Encouraging Internal Discovery of Violations

In 2013, violations discovered by registered entities through internal mechanisms comprised 79% of total violations in the SERC region. This is somewhat higher than the ERO Enterprise average of 73%.

Percentage of Violations by Method of Identification for SERC in 2013



ii. Ensuring the Timely Mitigation of Violations

SERC reported that it has taken several steps to encourage the timely mitigation of violations. First, SERC encourages and discusses the benefits of prompt submission of mitigation plans during its compliance seminars, open forum web conferences, and its compliance program updates to its board of directors. SERC requires a registered entity, when submitting a self-report form, to provide the status of its mitigating activities, detailed information on mitigating activities that are in progress or are completed, and the registered entity's efforts to prevent reoccurrence. To ensure timely follow-up and completion of mitigation plans, SERC has dedicated a staff member to mitigation processing for operations and planning violations, and several staff members share responsibility for CIP mitigation processing. SERC believes that the efforts of its enforcement staff to discover the complete scope of each violation are likely to result in the creation of mitigation plans that fully address each violation and reduce the likelihood of reoccurrence. SERC tracks mitigation plan information and documents in its compliance information tracking system, including mitigation plans submitted by entities, mitigating activities submitted through self-reports or other means, any revisions requested by SERC, and certifications of mitigation plan completion. If a registered entity does not include mitigating activities in its self-report form, SERC enforcement staff will contact the registered entity to ensure that mitigating activities are occurring. SERC may accept the mitigating activities and details to prevent reoccurrence, through the self-report form, as an informal mitigation plan. The review and acceptance process is similar for both mitigating activities and a formal mitigation plan. In the

case of mitigating activities, SERC does not send a formal notification of its review to the registered entity, but SERC reviews and confirms completion. SERC reported that it works with registered entities to answer questions about SERC's expectations for mitigation plans, and that it has occasionally requested that a registered entity revise a mitigation plan when proposed milestones would result in an extended period of noncompliance posing an additional risk to the BPS.

Many of the mitigation plans in the SERC region from 2010 and 2011 that are still in progress are for issues where SERC has combined more recent instances of noncompliance into the older enforcement action. In many of those cases, the registered entities have completed mitigating activities for the older occurrences but are still completing the mitigating activities for the newer occurrences.

SERC: Status of Mitigating Activity for Violations Discovered from 2007-2013 and Requiring Mitigation as of December 31, 2013[121]

Year of Discovery	% Completed	% in Progress
2013	27.8%	72.2%
2012	75.9%	24.1%
2011	81.7%	18.3%
2010	83.8%	16.2%
2009	100.0%	0.0%
2008	96.9%	3.1%
2007	100.0%	0.0%
Grand Total	**74.6%**	**25.4%**

As shown in the table above, as of December 31, 2013, SERC had a small number of 2008 violations for which mitigating activities had not been completed. These violations involve a single registered entity, and the violations are currently on hold due to a pending court case involving a similarly-situated registered entity. SERC reported that the pending court case has impacted its ability to verify the timely completion of mitigation for these violations. .

NERC will continue to work with SERC to ensure that newer violations are mitigated in a timely manner.

iii. Promoting Reliability through Enforcement Philosophy and Practices

SERC's enforcement philosophy is to manage all enforcement activities in an unbiased, fair, transparent, and consistent manner, affording registered entities appropriate due process. SERC strives to manage all enforcement actions in such a way to ensure consistent application of penalties for violations of Reliability Standards. SERC's view of the enforcement process is that

[121] This table reports the percentage of violations discovered from the years 2007 through 2013 with completed or open mitigation. This table excludes dismissed violations.

it should be used to assist registered entities in assessing, understanding, and managing risk to the BPS and deploying innovative solutions to not only restore compliance, but also mitigate risk, increase reliability, and prevent reoccurrence. SERC believes that it is important to leverage relationships with registered entities and other Regional Entities to promote effective collaboration, cooperation, and communication around significant risks to the reliability of the BPS to produce outcomes that effectively manage risk.

In its settlement processes, SERC has worked with registered entities, where appropriate, to accept the completion of certain activities above-and-beyond those required to ensure compliance with one or more Reliability Standards in lieu of the full monetary penalties permitted by the NERC *Sanction Guidelines*. These efforts allow registered entities to allocate their resources to those projects that can increase overall reliability and reduce the likelihood of future noncompliance.

As examples of above-and-beyond activities, SERC has accepted the following commitments as formal conditions of settlement. To address a series of CIP violations, a registered entity committed to centralize physical monitoring activities by implementing a new access control and video monitoring system and establishing a central security monitoring station.[122] To settle another series of CIP violations, a registered entity committed to conduct an evaluation of the U.S. Department of Energy Electricity Subsector Cybersecurity Capability Maturity Model (ES-C2M2) and share the evaluation with SERC; create and implement an action plan with the goal of increasing the entity's maturity indicator level in domains related to the CIP Reliability Standards; provide SERC with quarterly updates regarding its progress in implementing the action plan; and provide SERC with notification and evidence upon completion of activities.[123] NERC encourages SERC to continue deploying solutions such as these that promote reliability and insight into processes that can manage risk.

d. SERC's Implementation of Various Aspects of the CMEP

As noted in §II.D.1.a above, NERC conducts ongoing oversight activities to evaluate the effectiveness of each Regional Entity's implementation of the CMEP. These activities include regular reviews and periodic spot checks of specific Regional Entity processes. NERC's oversight activities give NERC an ongoing view into how effectively and efficiently the Regional Entity is executing its enforcement responsibilities. Below is a summary of some of NERC's more recent oversight activities specific to SERC.

With respect to the assessment of monetary penalties, SERC reviews previously-filed violations by SERC and other Regional Entities as part of its process to determine appropriate monetary penalties for violations. SERC seeks to apply a uniform process for determining monetary penalties that ensures that they are both (i) appropriate in light of the scope of, and risk posed by, the violations, and (ii) reasonable in light of monetary penalties levied by SERC and other Regional Entities for similar violations. NERC reviews all penalties submitted by SERC for appropriateness and consistency with monetary penalties assessed by SERC and other Regional Entities for violations of the same Reliability Standards and requirements occurring under similar

[122] *Unidentified registered entity*, NP14-18-000 (Dec. 30, 2013).

[123] *See Unidentified registered entity*, NP14-21-000 (Dec. 31, 2013).

facts and circumstances. NERC has found that SERC assesses monetary penalties that are appropriate and consistent with penalties assessed for similar violations.

Based on a spot check, NERC determined that SERC dismisses violations for appropriate reasons and generally includes the required information when issuing letters of dismissal. NERC identified opportunities for SERC to improve its letters of dismissal and communicated those opportunities to SERC. By implementing the recommended improvements, SERC can improve the quality of its compliance guidance to registered entities.

As part of its ongoing FFT review processes, NERC reviewed a sample of SERC FFT issues filed or posted during the assessment period to examine SERC's procedures for FFT processing and the application of those procedures to the FFT issues in its caseload. Following its review, NERC concluded that SERC's documented FFT process was adequate and that SERC follows its process. NERC noted that SERC generally provides all relevant information in its issue description, ensures the completion of mitigating activities, and considers violation history appropriately. NERC noted several ways that SERC could improve its FFT postings and related documentation to provide additional transparency to its determinations.

e. Conclusion

Based on NERC's review of the factors described above, NERC concludes that SERC has performed as an effective Regional Entity with respect to enforcement activities during the assessment period. SERC should adopt the recommendations for improvement provided as part of NERC's oversight activities.

7. Evaluation of Southwest Power Pool Regional Entity

a. Overview

In the three-year performance assessment, NERC expressed concerns about SPP RE's ability to process violations to completion in a timely manner.[124] During the current assessment period, SPP RE developed and streamlined enforcement procedures and increased enforcement staff in an effort to reduce processing times.[125] SPP RE now also has internal performance metrics in place to encourage the processing of violations as quickly as possible.

During the assessment period, SPP RE increased the number of FTE staff dedicated to enforcement from one FTE in 2009 to ten FTEs and one part-time employee as of December 31, 2013. Based on SPP RE's processing speed and efficiency as measured at the end of the assessment period, NERC views SPP RE's enforcement staffing to be sufficient to process the number of violations that it receives in accordance with ERO Enterprise performance objectives.

SPP RE closed the assessment period with a Caseload Index consistent with the ERO Enterprise average. SPP RE also made remarkable progress in meeting older caseload reduction goals for 2012 and 2013. Finally, NERC has reviewed SPP RE's enforcement-related processes

[124] *Three-Year ERO Performance Assessment Report*, Attachment 3 at 24.

[125] 2014 JRESA, Appendix 2-B at 5.

as part of its oversight role and found that, while areas for improvement remain, SPP RE generally implements those processes in a satisfactory manner.

SPP RE staff have actively participated in the development of RAI. SPP RE staff participated in several NERC working groups that are developing, testing, and implementing the Aggregation of Minimal Risk Issues and Enforcement Discretion pilot programs. SPP RE staff took a leadership role in the development of the *ERO Enterprise Mitigation Plan Guide*. In addition, SPP RE staff also participated in various RAI projects and programs falling under the compliance function. This participation is vital as the ERO Enterprise shifts toward a risk-based model of compliance and enforcement.

In light of all of the relevant factors, which are explained more fully below, NERC concludes that SPP RE has performed as an effective Regional Entity during the assessment period with respect to enforcement activities. NERC will continue to work with SPP RE to ensure that violations are processed and mitigated promptly, with an emphasis on ensuring the completion of mitigation for older violations.

b. Evaluation of Caseload Processing Efficiency

i. The Composition of SPP RE's Caseload

During the assessment period, SPP RE reported 1,041 violations to NERC.

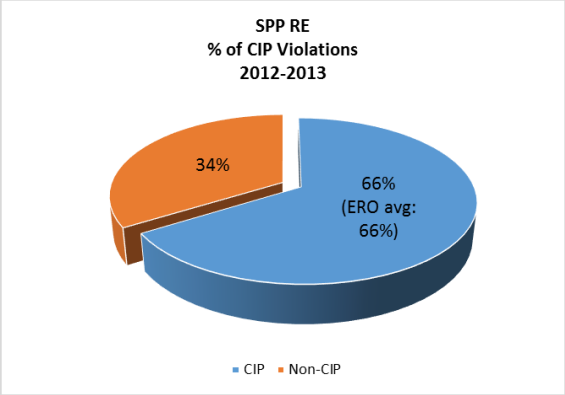
Violations for SPP RE 2009-2013 by Year Reported to NERC[126]

Year Reported to NERC	Violations Reported
2009	132
2010	254
2011	291
2012	173
2013	191
Total	**1041**

As shown in the table above, SPP RE reported its highest number of violations in 2010 and 2011. CIP violations were the majority of those violations. In the years 2012 and 2013, violations of CIP Reliability Standards comprised 66% of total violations. This is consistent with the ERO Enterprise average.

[126] For an explanation of the methodology used to calculate the data in this table and throughout this §II.D, *see supra* n. 76.

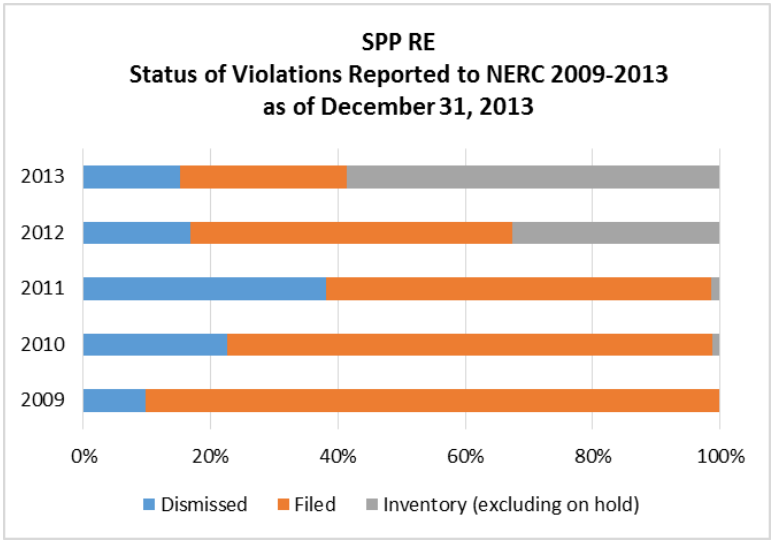
Type of Violations Reported to NERC by SPP RE, 2012-2013



Approximately 56% of CIP violations were discovered through internal mechanisms.

Of the total violations reported by SPP RE to NERC during the assessment period, approximately 175 violations, or about 17%, remained to be processed as of December 31, 2013 (excluding on-hold violations). As demonstrated in the table below, as of December 31, 2013, SPP RE had processed all violations that were reported to NERC in 2009; 98.8% of violations reported to NERC in 2010; 98.6% of violations reported to NERC in 2011; and 67.4% of violations reported to NERC in 2012 (excluding on hold violations).

Status of Violations Reported to NERC 2009-2013 for SPP RE



SPP RE processed approximately 41% of violations reported to NERC in 2013. This is consistent with the ERO 2013 processing rate of 39%. The percentage of SPP RE's caseload consisting of violations reported to NERC in 2013 (64%) is also consistent with the overall ERO Enterprise average of 67%.

ii. Caseload Index

The Caseload Index for SPP RE is 8.3 months as of December 31, 2013. This is slightly higher than the ERO Enterprise Caseload Index of approximately 6.5 months, but nevertheless lower than the 2013 ERO Enterprise average goal of 10 months.

In light of SPP RE's Caseload Index and as reflected in the characteristics of its caseload (i.e., the percentage of SPP RE's caseload consisting of older violations is consistent with the ERO average), it appears that SPP RE's efforts to streamline its enforcement processes and increase its enforcement staffing during the assessment period have been effective.

iii. Efforts to Reduce Older Caseload

In 2013, SPP RE reduced its pre-2012 caseload by 96%.[127] NERC commends SPP RE for its responsiveness and efforts to achieve this important ERO Enterprise goal. SPP RE states that several factors specific to the remaining violations caused delays in processing, but SPP RE expects to resolve those issues in 2014.

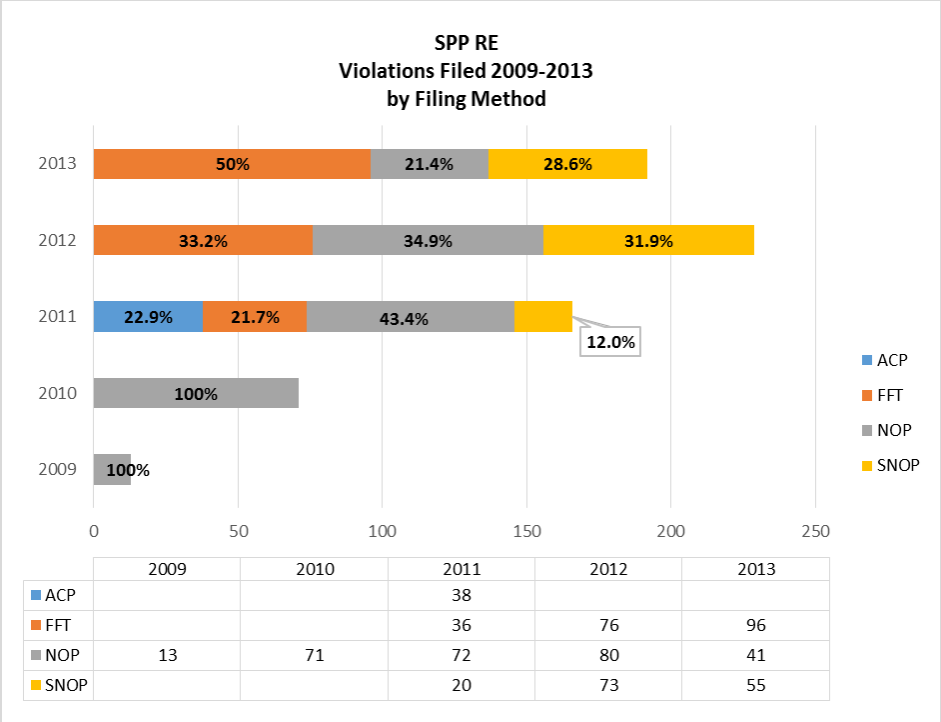
Based on the current composition of its inventory of violations available to be processed and its largely successful efforts in processing its older violations, SPP RE is positioned to achieve the goal of ensuring that violations are processed before reaching 24 months in age.

iv. Implementation of Streamlined Enforcement Processing Mechanisms

From 2007 through 2010, SPP RE filed a total of 89 violations. In 2011, SPP RE filed a total of 166 violations, almost double the total number of violations from the previous three years combined. SPP RE credits its success in improving its violation processing rate to several factors. SPP RE developed internal enforcement procedures, streamlined its enforcement processes, and dedicated resources to increasing both the number and maturity of its enforcement staff. For example, SPP RE decreased the time it spends drafting CMEP required and related documents by utilizing its compliance database to automate the issuance of a number of documents. In addition, SPP RE effectively implemented alternative enforcement processing mechanisms, including using FFT to process its lower-risk violations, as demonstrated in the table below.

[127] All but four pre-2012 violations were processed before the end of 2013. Of the four violations, two were MRRE violations for which another Regional Entity took lead responsibility. One violation was being held pending an interpretation of the associated Reliability Standard.

Violations Filed per Year by Filing Method for SPP RE, 2009-2013



	2009	2010	2011	2012	2013
ACP			38		
FFT			36	76	96
NOP	13	71	72	80	41
SNOP			20	73	55

SPP RE filed the majority of violations using FFT or SNOP in 2012 and 2013. In 2013, the percentage of FFTs relative to SNOPs increased notably. SPP RE generally limits the use of the FFT process to minimal risk issues, and it uses the SNOP process for those violations that do not represent a serious or substantial risk to the BPS and do not qualify for FFT disposition. Every FFT and SNOP is reviewed by the SPP RE sanction review team to ensure consistency and uniform application. Going forward, NERC encourages SPP RE to continue its review processes and consider increasing the use of FFT for moderate risk issues that qualify for FFT.

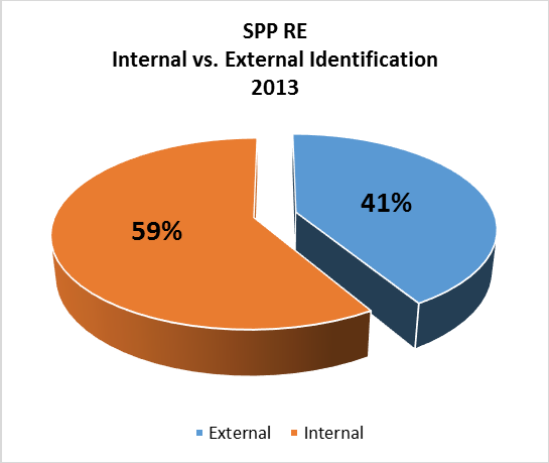
c. Improving Reliability

i. Encouraging Internal Discovery of Violations

SPP RE regularly encourages the value of self-reporting, and it gives presentations on how to self-report effectively during its regional workshops. Additionally, SPP RE discusses the value of self-reporting when it gives penalty determination presentations at workshops.

In 2013, violations discovered by registered entities through internal mechanisms comprised 59% of total violations in the SPP RE region. This is lower than the ERO Enterprise average of 73%. Stated differently, during the assessment period, SPP RE discovered a higher percentage of violations through external methods (i.e., compliance audit and spot check) than other Regional Entities.

Percentage of Violations by Method of Identification for SPP RE in 2013



As noted above, NERC and the Regional Entities are working to understand the regional variations in the percentages of noncompliance discovered through self-discovery and audits across the ERO Enterprise. Understanding these differences, and how they may relate to registered entity internal controls and management practices, will allow NERC and the Regional Entities to provide the right incentives for discovering and self-reporting noncompliance.

ii. Ensuring the Timely Mitigation of Violations

SPP RE has undertaken a number of efforts to encourage the timely mitigation of violations. It has implemented internal metrics to: (i) encourage enforcement staff to solicit mitigation plans as soon as possible for higher-risk violations; (ii) measure whether mitigation plans are accepted or rejected within 30 days of submission; and (iii) measure whether mitigation plan completion evidence is reviewed by SPP RE staff within 30 days of when the registered entity's certification of mitigation plan completion and associated evidence are submitted. SPP RE tracks mitigation plan information in its webCDMS. SPP RE has put standardized processes in place for the review and approval of registered entity mitigation plans, and the associated forms become part of the violation case record.

SPP RE requires registered entities to complete mitigation plans for all compliance issues identified for FFT treatment, and it requires each registered entity desiring to remain in settlement negotiations to submit an acceptable mitigation plan. SPP RE typically requires mitigation plans to be completed before it will execute a settlement agreement and file it with NERC. [128]

SPP RE has strengthened its active monitoring of mitigation plans by increasing its communication with registered entities since 2010. SPP RE issues email reminder notices to registered entities as due dates approach. SPP RE staff has continued to communicate and give

[128] SPP RE does not yet accept completion of mitigating activities in lieu of a formal mitigation plan; however, SPP RE reported that will accept mitigating activities as soon as appropriate changes are made to the webCDMS system.

presentations to registered entities regarding best practices for submitting and managing information associated with self-reports, self-certifications, and mitigation plans.

As demonstrated in the table below, SPP RE has made substantial progress in ensuring that older violations have been mitigated, with 100% of violations discovered from 2007-2009 having completed mitigation.

SPP RE: Status of Mitigating Activity for Violations Discovered from 2007-2013 and Requiring Mitigation as of December 31, 2013[129]

Year of Discovery	% Completed	% in Progress
2013	43.6%	56.4%
2012	77.8%	22.2%
2011	96.7%	3.3%
2010	96.0%	4.0%
2009	100.0%	0.0%
2008	100.0%	0.0%
2007	100.0%	0.0%
Grand Total	**84.0%**	**16.0%**

NERC is working closely with SPP RE to understand the nature of the violations with open mitigation, particularly the older violations. NERC is also working with SPP RE to ensure that violations are mitigated in a timely manner.

iii. Promoting Reliability through Enforcement Philosophy and Practices

SPP RE reported that it has been its experience that most registered entities desire to be as reliable and as compliant as possible, and that avoiding or minimizing penalties and sanctions is only a secondary motivation. SPP RE reported that it has undertaken a number of efforts to improve the efficiency of its enforcement processes and encourage the prompt mitigation of violations. For instance, SPP RE has supplied registered entities with online training videos covering topics such as evidence submission, mitigation processing, and self-reporting. SPP RE was recently awarded the Bronze Quill Award of Merit from the International Association of Business Communicators, Arkansas Chapter for the quality of its video library. SPP RE developed a flow diagram that is used for small group discussions at regional workshops. The diagram facilitates conversation about the enforcement process with registered entities and provides a visual aid for how violations and mitigation plans move through the enforcement process. SPP RE has also conducted on-site visits with several registered entities to discuss internal compliance program improvements following negative audit findings.

[129] This table reports the percentage of violations discovered from the years 2007 through 2013 with completed or open mitigation. This table excludes dismissed violations.

SPP RE's enforcement group tracks various metrics on a monthly basis, including: (i) the expediting of high risk violations; (ii) caseload processing time: (iii) mitigation plan acceptance review time; (iv) mitigation plan completion review time; (v) processing of pre-2013 violations; (vi) incoming compliance issue triage time; and (vii) case record review and close-out time. To facilitate transparency, SPP RE posts a monthly metrics tracking dashboard covering these areas on its web page.[130]

The FFT process has enabled SPP RE to improve its processing efficiency substantially. As a result, SPP RE reported that it has been able to devote a substantial portion of the efforts of its personnel toward evaluating and processing higher-risk violations.

In its settlement processes, SPP RE has worked with registered entities, where appropriate, to accept the completion of certain activities above-and-beyond those required to ensure compliance with one or more Reliability Standards in lieu of the full monetary penalties permitted by the NERC *Sanction Guidelines*. For example, SPP RE has considered a registered entity's initiatives to audit and improve its internal compliance program to be a mitigating factor in SPP RE's penalty determination. NERC encourages SPP RE to continue deploying such solutions that promote reliability and insight into processes that can manage risk.

d. SPP RE's Implementation of Various Aspects of the CMEP

As noted in §II.D.1.a above, NERC conducts ongoing oversight activities to evaluate the effectiveness of each Regional Entity's implementation of the CMEP. These activities include regular reviews and periodic spot checks of specific Regional Entity processes. NERC's oversight activities give NERC an ongoing view into how effectively and efficiently the Regional Entity is executing its enforcement responsibilities. Below is a summary of some of NERC's more recent oversight activities specific to SPP RE.

With respect to the assessment of monetary penalties, SPP RE requires its case managers to follow the penalty guidance established by NERC and the Commission. Each violation and its associated penalty must be approved by the SPP RE sanction review team. When presenting a violation and proposed penalty to the sanction review team, an SPP RE case manager will provide the basis for the proposed penalty and a comparison to similar violations and the penalties assigned to those violations. The SPP RE sanction review team will then review the violation and proposed penalty to determine whether the proposed penalty is justified, reasonable, and consistent with penalties assessed for similar violations by SPP RE and by other Regional Entities. NERC reviews all penalties submitted by SPP RE for appropriateness and consistency with monetary penalties assessed by SPP RE and other Regional Entities for violations of the same Reliability Standards and requirements occurring under similar facts and circumstances. NERC has found that SPP RE assesses monetary penalties that are appropriate and consistent with penalties assessed for similar violations.

Based on a spot check, NERC determined that SPP RE dismisses violations for appropriate reasons and generally includes the required information when issuing letters of dismissal. NERC

[130] *See* http://www.spp.org/section.asp?group=2754&pageID=27.

identified opportunities where SPP RE could improve its letters of dismissal and communicated those opportunities to SPP RE. SPP RE has already implemented at least one of the recommended improvements. These improvements will ensure SPP RE has access to the information it needs to process each violation properly. Such efforts will also assist NERC in its oversight role and allow the Commission to evaluate the efficiency and effectiveness of the dismissal process.

As part of its ongoing FFT review processes, NERC reviewed a sample of SPP RE FFT issues filed or posted during the assessment period to examine SPP RE's procedures for FFT processing and the application of those procedures to the FFT issues in its caseload. NERC noted that SPP RE developed a checklist which delineates the steps that need to be taken by each SPP RE staff member and indicates that the final document will be attached to the record for tracking purposes. If completed on a regular basis, this checklist could provide valuable insight into SPP RE's determination of FFT treatment and facilitate future review by NERC and the Commission. NERC recommended several areas in which SPP RE could improve its FFT postings and related documentation to provide additional transparency to its determinations.

e. Conclusion

Based on NERC's review of the factors described above, NERC concludes that SPP RE has performed as an effective Regional Entity with respect to enforcement activities during the assessment period. SPP RE should adopt the recommendations for improvement provided as part of NERC's oversight activities.

8. Evaluation of Texas Reliability Entity, Inc.

a. Overview

In the three-year performance assessment, NERC concluded that Texas Regional Entity was an effective Regional Entity, and it praised Texas Regional Entity's processing efficiency and focus on identifying higher-risk violations that result from failure to comply with Reliability Standards.[131] At the time, NERC noted questions regarding the contrast between the high percentage of "failure to perform" violations and the low number of violations recommended for a zero-dollar penalty. Texas RE reported that it recommended zero-dollar penalties in 2007 and 2008 for most cases as the Reliability Standards were new, and registered entities were still learning how to comply with them. Texas RE reported that it began recommending more monetary penalties for "failure to perform" violations in 2010 in an effort to deter noncompliance. As the streamlined enforcement mechanisms were developed and implemented, Texas RE began using these mechanisms to process violations posing a low risk to reliability and that had been mitigated.[132] Texas RE also made organizational changes related to its enforcement processes in late 2013 to provide for a clear delineation between processing tasks; Texas RE believes that these changes have resulted in efficiency gains and decreased processing time.

[131] *Three-Year ERO Performance Assessment Report*, Attachment 3 at 26.

[132] 2014 JRESA, Appendix 2-B at 6.

During the assessment period, Texas RE increased the number of FTE staff dedicated to enforcement from 3 in 2009 to 11 as of December 31, 2013. Based on Texas RE's processing speed and efficiency as measured at the end of the assessment period, NERC views Texas RE's enforcement staffing to be sufficient to process the number of violations that it receives.

Texas RE ended the assessment period with a Caseload Index that was the lowest among all Regional Entities. Texas RE processed all violations discovered before 2012 in furtherance of an ERO Enterprise goal. Texas RE's caseload tends to consist of more-recent violations, and generally, Texas RE has made progress in ensuring that older violations have completed mitigation. Finally, NERC has reviewed Texas RE's enforcement-related processes as part of its oversight role and found that, while areas for improvement remain, Texas RE generally implements those processes in a satisfactory manner.

In addition, Texas RE staff have actively participated in the development of RAI. Many Texas RE employees worked on various aspects of RAI in collaboration with NERC and the other regions. Texas RE staff participated in the Aggregation of Minimal Risk Issues and Enforcement Discretion pilot programs and served on the *ERO Self-Report User Guide* and *ERO Enterprise Mitigation Plan Guide* drafting teams. Texas RE staff also participated in several compliance-related programs under RAI. This participation is vital as the ERO Enterprise shifts toward a risk-based model of compliance and enforcement.

As explained more fully below, based on Texas RE's performance in several enforcement processing metrics and the results of NERC's oversight activities, NERC concludes that Texas RE has performed as an effective Regional Entity with respect to enforcement activities during the assessment period. NERC will continue to work with Texas RE to ensure that violations are mitigated promptly.

b. Evaluation of Caseload Processing Efficiency

i. The Composition of Texas RE's Caseload

During the assessment period, Texas RE reported 861 violations to NERC.

Violations for Texas RE 2009-2013 by Year Reported to NERC[133]

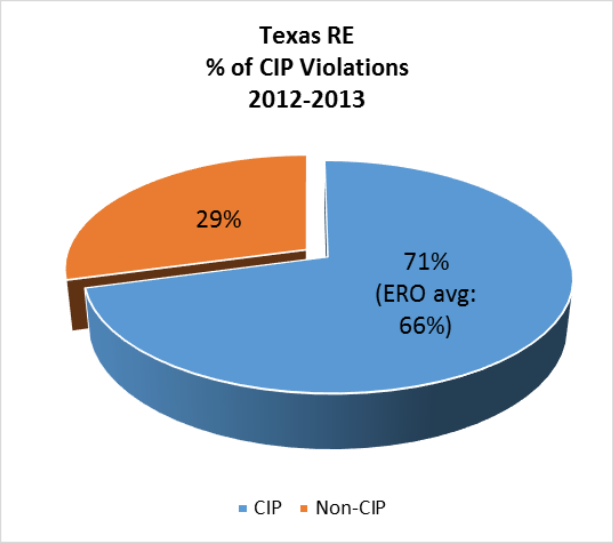
Year of Submission	Violations Reported
2009	14
2010	51
2011	430
2012	197
2013	169

[133] For an explanation of the methodology used to calculate the data in this table and throughout this §II.D, *see supra* n. 76.

Total	**861**

As shown in the table above, Texas RE reported a spike in violations in 2011..[134] The violations reported to NERC in 2011 were split almost evenly between CIP and non-CIP violations and internal and external methods of discovery. In the years 2012 and 2013, violations of CIP Reliability Standards represented a higher percentage of total violations in the Texas RE region than the ERO Enterprise as a whole.

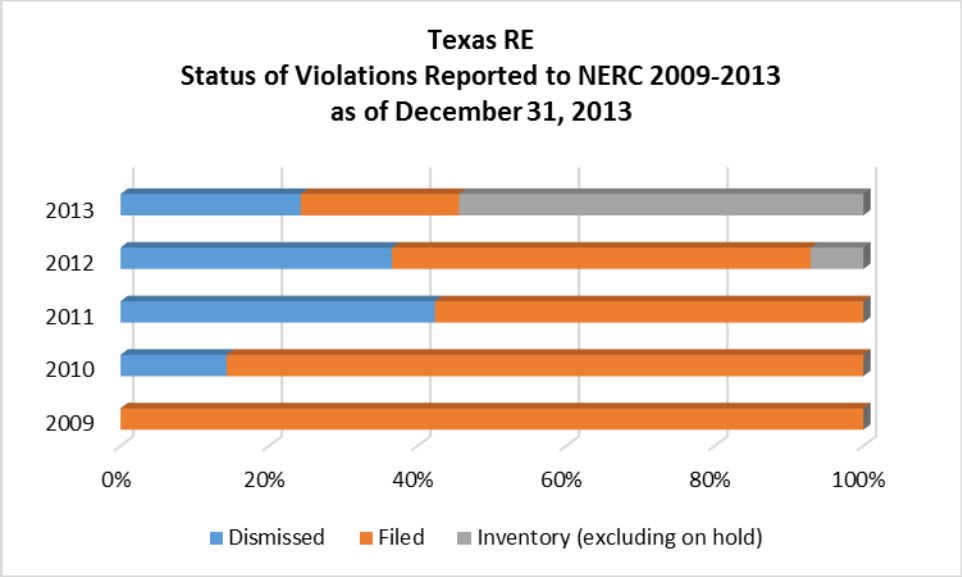
Type of Violations Reported to NERC by Texas RE, 2012-2013



Of the total violations reported to NERC during the assessment period, 106 violations, or approximately 12%, remained to be processed as of December 31, 2013 (excluding violations that are held by appeal, a court, or a regulator). As demonstrated in the table below, Texas RE has processed all violations reported to NERC in 2009, 2010, and 2011 (excluding on hold violations). Texas RE processed approximately 93% of violations reported to NERC in 2012.

[134] When adjusted for year of discovery, 157 violations were discovered in 2010, and 298 violations were discovered in 2011.

Status of Violations Reported to NERC 2009-2013 for Texas RE



Texas RE processed approximately 46% of violations reported to NERC in 2013, which is better than the ERO Enterprise average 2013 processing rate of 39%. Approximately 87% of the violations available for processing in Texas RE's inventory consist of violations reported to NERC in 2013. This greatly exceeds the overall ERO Enterprise average of 67%. Texas RE appears to be moving toward a caseload consisting primarily of newer violations.

ii. Caseload Index

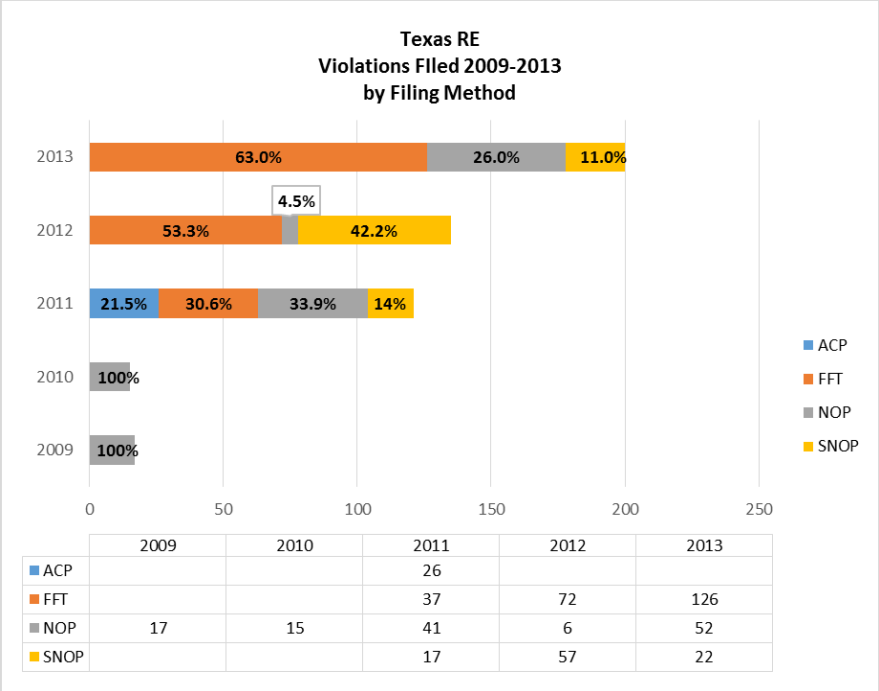
The Caseload Index for Texas RE is 3.8 months as of December 31, 2013. This is the lowest of all Regional Entities and notably better than the ERO Enterprise Caseload Index of approximately 6.5 months.

Based on the current composition of its inventory of violations available to be processed and its success in achieving the timely processing of violations to date, Texas RE is well-positioned to achieve the goal of ensuring that violations are processed before reaching 24 months in age.

iii. Implementation of Streamlined Enforcement Processing Mechanisms

A number of factors are responsible for Texas RE's successes in processing its caseload. As demonstrated in the table below, Texas RE effectively used alternative processing mechanisms to process a substantial portion of its caseload during the assessment period. In 2011, following the implementation of the streamlined enforcement processing mechanisms, Texas RE filed 121 violations – almost quadruple the number of violations filed in the previous two years combined.

Violations Filed per Year by Filing Method for Texas RE, 2009-2013



	2009	2010	2011	2012	2013
ACP			26		
FFT			37	72	126
NOP	17	15	41	6	52
SNOP			17	57	22

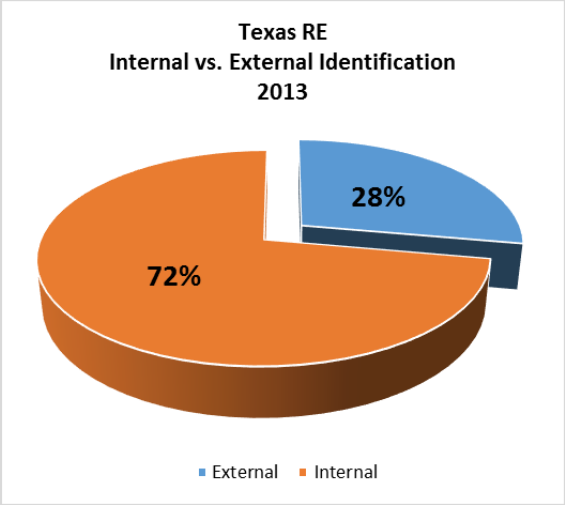
Texas RE reviews posted FFT and SNOP filings before determining the disposition method it will use for a particular violation, and it coordinates all FFT and SNOP-related issues with NERC. These methods help ensure the consistent application of FFTs and SNOPs across the Regional Entities. In 2011 and in every year since, Texas RE filed the majority of its violations using the streamlined enforcement processing mechanisms, including using FFT to file lower-risk violations of the CIP Reliability Standards. NERC expects that Texas RE will continue to reserve the NOP format for violations that require it and take advantage of further process refinements available under RAI. Additional information regarding Texas RE's application of FFT is presented later in this assessment.

c. Improving Reliability

i. Encouraging Internal Discovery of Violations

In 2013, violations discovered by registered entities through internal mechanisms comprised 72% of total violations in the Texas RE region. This is consistent with the ERO Enterprise average of 73%.

Percentage of Violations by Method of Identification for Texas RE in 2013



ii. Ensuring the Timely Mitigation of Violations

During the assessment period, Texas RE reported that it implemented a number of measures to ensure the timely mitigation of violations. Texas RE stressed the importance of prompt mitigation in workshops and other communications with registered entities and encouraged early completion of mitigation. Texas RE modified its self-report form to require a description of mitigating activities, preventative measures, and a date of mitigation. As a result of this modification, Texas RE began receiving more information regarding mitigation earlier in the enforcement process. Texas RE has also strengthened processes and documentation standards for the review, approval, tracking, and certification of mitigation plans. When reviewing a mitigation plan, Texas RE determines if the completion date is reasonable, considering the nature of the violation. Texas RE has requested that mitigation plans be revised because Texas RE determined that the completion date was unreasonable. Texas RE tracks the mitigation plan or mitigation activities completion date and has informed registered entities that violations cannot be closed until the mitigation is complete. Texas RE also tracks mitigation plan milestones in webCDMS and provides notifications to registered entities for upcoming milestones. In an effort to hold registered entities accountable, Texas RE will only discuss settlement and suspend deadlines if the entity submits a mitigation plan, or Texas RE has verified that the entity has mitigated the violation.

As demonstrated in the table below, Texas RE has made substantial progress in ensuring that older violations have completed mitigation. Only three violations from 2010 through 2011 remained to be mitigated at the end of the assessment period.

Texas RE: Status of Mitigating Activity for Violations Discovered from 2007-2013 and Requiring Mitigation as of December 31, 2013[135]

Year of Discovery	% Completed	% in Progress
2013	28.1%	71.9%
2012	91.2%	8.8%
2011	99.4%	0.6%
2010	98.1%	1.9%
2009	100.0%	0.0%
2008	100.0%	0.0%
2007	100.0%	0.0%
Grand Total	**82.5%**	**17.5%**

NERC will continue to work closely with Texas RE to ensure the completion of mitigating activities.

iii. Promoting Reliability through Enforcement Philosophy and Practices

Texas RE's enforcement philosophy is to abide by the requirements of the NERC ROP, reserve the enforcement process for those violations posing a serious or substantial risk to the reliability of the BPS, and encourage the development of strong internal compliance programs and internal controls. As part of encouraging strong internal controls, Texas RE encourages registered entities to address the results of internal controls by self-reporting and mitigating violations promptly. Texas RE may consider the method of discovery, presence of internal compliance programs, and the prompt mitigation of violations among the factors in determining how to dispose of a violation (i.e., FFT, SNOP, or NOP) and in assessing potential penalties.

In its settlement processes, Texas RE has worked with registered entities, where appropriate, to accept the completion of certain activities above-and-beyond those required to ensure compliance with one or more Reliability Standards in lieu of the full monetary penalties permitted by the NERC *Sanction Guidelines*. These efforts allow registered entities to allocate their resources to those projects that can increase overall reliability and reduce the likelihood of future noncompliance.

As examples of above-and-beyond activities, registered entities in the Texas RE region have committed to hire additional compliance staff, install new software to track maintenance and testing intervals, contribute to future compliance efforts (such as making an entity's SME available for a compliance workshop), develop additional training for staff, perform additional technical modifications beyond those required to achieve compliance, and upgrade physical security measures. NERC encourages Texas RE to continue deploying solutions such as these that promote reliability and insight into processes that can manage risk.

[135] This table reports the percentage of violations discovered from the years 2007 through 2013 with completed or open mitigation. This table excludes dismissed violations.

d. Texas RE's Implementation of Various Aspects of the CMEP

As noted in §II.D.1.a above, NERC conducts ongoing oversight activities to evaluate the effectiveness of each Regional Entity's implementation of the CMEP. These activities include regular reviews and periodic spot checks of specific Regional Entity processes. NERC's oversight activities give NERC an ongoing view into how effectively and efficiently the Regional Entity executes its enforcement responsibilities. Below is a summary of some of NERC's more recent oversight activities specific to Texas RE.

Texas RE calculates penalties using the NERC *Sanction Guidelines* and reviews its determinations in relation to similar penalties assessed by Texas RE and by other Regional Entities. NERC reviews all penalties submitted by Texas RE for appropriateness and consistency with monetary penalties assessed by Texas RE and other Regional Entities for violations of the same Reliability Standards and requirements occurring under similar facts and circumstances. NERC has found that Texas RE assesses monetary penalties that are appropriate and consistent with penalties assessed for similar violations.

Based on a spot check, NERC determined that Texas RE dismisses violations for appropriate reasons and generally includes the required information when issuing letters of dismissal. NERC identified opportunities for Texas RE to improve its letters of dismissal and communicated those opportunities to Texas RE. By implementing the recommended improvements, Texas RE can improve the quality of its compliance guidance to registered entities.

As part of its ongoing FFT review processes, NERC reviewed a sample of Texas RE FFT issues filed or posted during the assessment period to examine Texas RE's procedures for FFT processing and the application of those procedures to the FFT issues in its caseload. Following its review, NERC concluded that Texas RE maintains adequate documentation and written procedures for its FFT process. NERC noted that Texas RE developed a process checklist which could prove to be a useful tool for FFT processing, provided the checklist is completed on a consistent basis. NERC further concluded that Texas RE generally provides an adequate description of the issue in its FFT postings. NERC noted several ways that Texas RE could improve its FFT postings and related documentation to provide additional transparency to its determinations.

e. Conclusion

Based on NERC's review of the factors described above, NERC concludes that Texas RE has performed as an effective Regional Entity with respect to enforcement activities during the assessment period. Texas RE should adopt the recommendations for improvement provided as part of NERC's oversight activities.

9. Evaluation of Western Electricity Coordinating Council

a. Overview

In the three-year performance assessment, NERC concluded that WECC was one of the less effective Regional Entities in carrying out its compliance obligations, but noted that WECC was starting to make significant strides in reducing the portion of violations described as its "backlog" in the first half of 2009. NERC encouraged WECC to create a stronger separation of its compliance encouragement efforts from its enforcement activities and to maintain its focus on processing violations to completion.[136]

During the assessment period, WECC has taken several steps to address the concerns identified by NERC in the three-year performance assessment. WECC reported that it has enhanced, streamlined, and documented all of its enforcement processes with the assistance of dedicated enforcement SMEs. Further, WECC has implemented the alternative enforcement processing mechanisms. WECC calculated its processing time (from intake through submittal to NERC) to be less than five months, on average. WECC also has enhanced its compliance encouragement activities while maintaining separation from its enforcement activities.[137]

During the assessment period, WECC increased the number of FTE staff dedicated to enforcement processing from 6 in 2009 to 8 as of December 31, 2013.[138] Based on WECC's processing speed and efficiency as measured at the end of the assessment period, NERC views WECC's enforcement processing staffing to be sufficient to process the number of violations that it receives.

WECC ended the assessment period with a better-than-average Caseload Index. In addition, WECC made substantial progress in processing the especially large number of violations that it received during the assessment period, including processing almost all of its older caseload. NERC notes that WECC has a few older violations that still need to be mitigated and processed. In addition, NERC has reviewed WECC's enforcement-related processes as part of its oversight role and found that, while areas for improvement remain, WECC generally implements those processes in a satisfactory manner.

NERC recognizes the contributions WECC staff have made in the development of RAI. WECC staff participated in the Enforcement Discretion pilot program and served in leadership roles on the *ERO Self-Report User Guide* and *ERO Enterprise Mitigation Plan Guide* drafting teams. This participation is vital as the ERO Enterprise shifts toward a risk-based model of compliance and enforcement.

In light of all of the relevant factors, which are explained more fully below, NERC concludes that WECC has performed as an effective Regional Entity with respect to enforcement

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[136] *Three-Year ERO Performance Assessment Report*, Attachment 3 at 26.

[137] 2014 JRESA Appendix 2B at 6-7.

[138] WECC has additional staff dedicated to reviewing violations from a technical perspective and reviewing and approving mitigation plans.

activities during the assessment period. NERC will continue to work with WECC to ensure that violations are mitigated and processed promptly.

b. Evaluation of Caseload Processing Efficiency

i. The Composition of WECC's Caseload

During the assessment period, WECC reported 3,183 violations[139] to NERC.

Violations for WECC 2009-2013 by Year Reported to NERC[140]

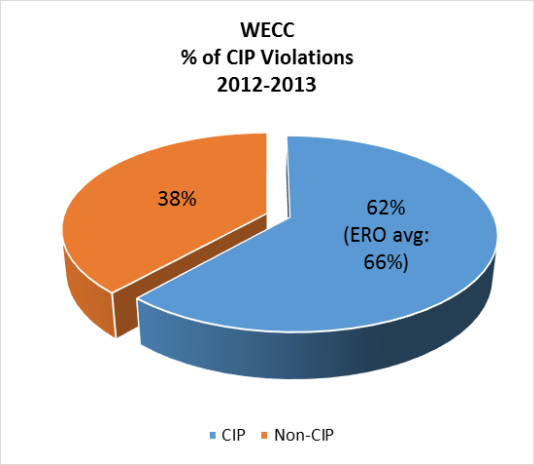
Year Reported to NERC	Violations Reported
2009	571
2010	550
2011	807
2012	818
2013	437
Total	**3,183**

As shown in the table above, WECC reported the most violations to NERC in 2011 and 2012. CIP violations comprised more than half of total violations in 2011 through 2012. In the years 2012 and 2013, violations of CIP Reliability Standards represented a slightly lower percentage of total violations in the WECC region (62%) than the ERO Enterprise as a whole.

[139] This table reflects U.S. violations only.

[140] For an explanation of the methodology used to calculate the data in this table and throughout this §II.D, *see supra* n. 76.

Type of Violations Reported to NERC by WECC, 2012-2013

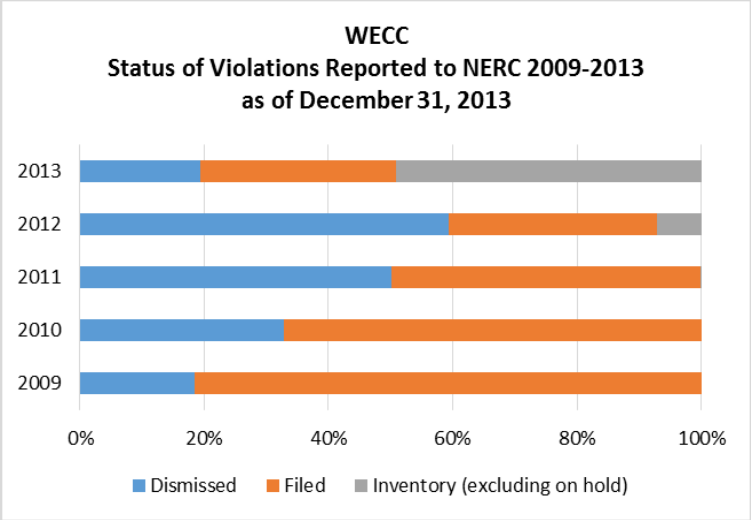


More than 85% of the total number of CIP violations reported by WECC to NERC in 2012 and 2013 were identified through internal means; nearly half of these CIP violations were later dismissed.[141]

Of the total violations reported by WECC to NERC during the assessment period, approximately 254 violations, or approximately 9%, remained to be processed as of December 31, 2013 (excluding violations that are held by appeal, a court, or a regulator). As demonstrated in the table below, WECC has processed 100% of violations reported to NERC in 2009 and 2010 and 99.9% of violations reported to NERC in 2011 (excluding on hold violations). WECC has processed approximately 93% of violations reported to NERC in 2012.

[141] WECC had a larger number of dismissals than other Regional Entities during the assessment period as a result of duplicate self-reporting. In early 2012, WECC had a number of violations where an entity submitted both a self-report and a self-certification. Since that time, WECC implemented a process to check for duplicate violations. In addition, the NERC ROP were amended to add several enhancements to the preliminary screen process; part of this process requires Regional Entities to confirm that new violations are not duplicates of violations already in process.

Status of Violations Reported to NERC 2009-2013 for WECC



WECC processed nearly 51% of violations reported to NERC in 2013. This is notably higher than the ERO 2013 processing rate of 39%. Approximately 78% of the violations available for processing in the WECC region consist of violations reported to NERC in 2013. This is notably better the overall ERO Enterprise average of 67%. WECC appears to be moving toward a caseload consisting primarily of newer violations.

ii. Caseload Index

The Caseload Index for WECC is 5.7 months as of December 31, 2013. This compares favorably to the ERO Enterprise Caseload Index of approximately 6.5 months.

Based on its achievements in processing its caseload to date and its Caseload Index, it appears that WECC's efforts to enhance and streamline its enforcement processes have been effective.

iii. Efforts to Reduce Older Caseload

In 2013, WECC processed 98% of remaining cases in its pre-2012 caseload. NERC commends WECC for its responsiveness and efforts to achieve this important ERO Enterprise goal.

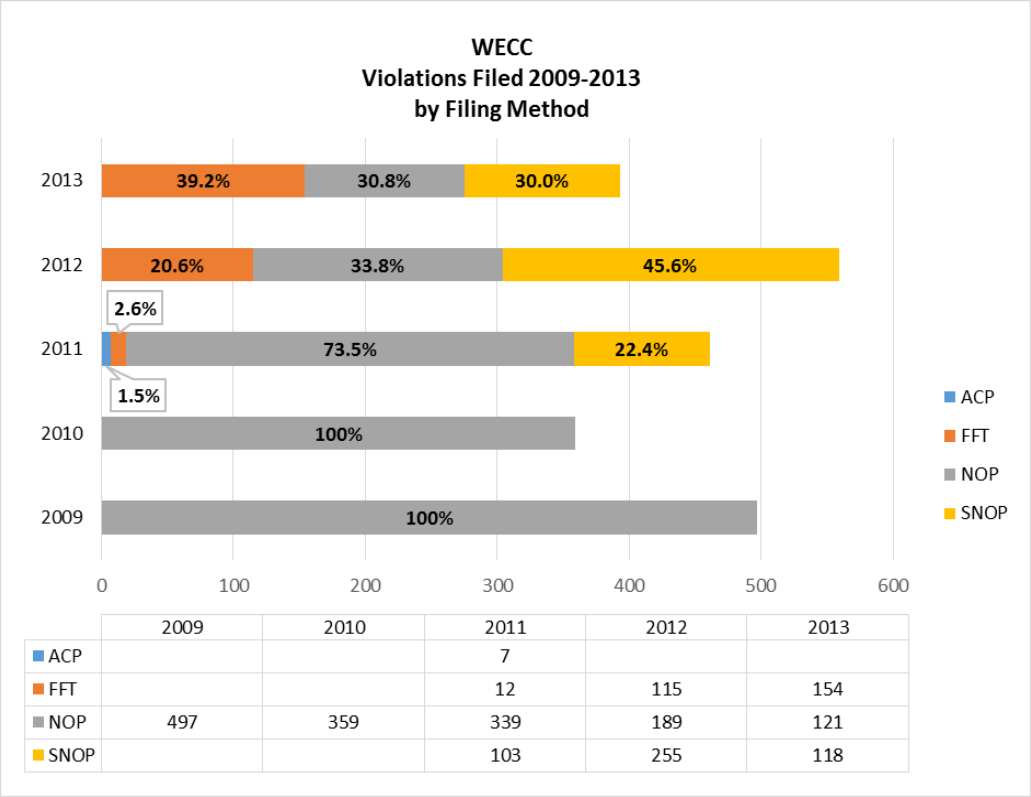
Based on the current composition of its inventory of violations to be processed and its successful effort in processing its older violations, WECC is well-positioned to achieve the goal of ensuring that violations are processed before reaching 24 months in age.

iv. Implementation of Streamlined Enforcement Processing Mechanisms

A number of factors are responsible for WECC's successes in processing its caseload. As

demonstrated in the table below, WECC effectively used streamlined processing mechanisms to process a substantial portion of its caseload during the assessment period. WECC did not implement streamlined processing mechanisms as quickly as some other Regional Entities, but by 2012, WECC was using the streamlined processing mechanisms to file nearly two-thirds of its violations.

Violations Filed per Year by Filing Method for WECC, 2009-2013



	2009	2010	2011	2012	2013
ACP			7		
FFT			12	115	154
NOP	497	359	339	189	121
SNOP			103	255	118

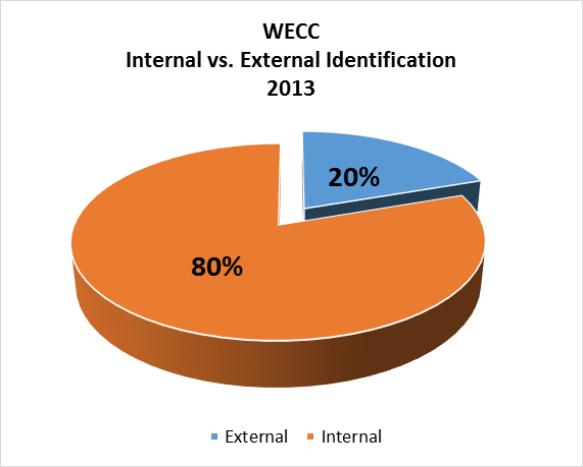
WECC has enhanced, streamlined, and documented all of its enforcement processes; WECC believes that these efforts will help ensure effective and consistent use of the enforcement processing mechanisms (including FFT and SNOP). NERC encourages WECC to continue its utilization of alternative enforcement processing mechanisms. Going forward, NERC expects that WECC will continue to use the NOP format for violations that require it and take advantage of further process refinements under RAI. Additional information regarding WECC's implementation of FFT is presented later in this assessment.

c. Improving Reliability

i. Encouraging Internal Discovery of Violations

In 2013, self-identified violations comprised 80% of total violations in the WECC region. This is somewhat higher than the ERO Enterprise average of 73%.

Percentage of Violations by Method of Identification for WECC in 2013



ii. Ensuring the Timely Mitigation of Violations

During the assessment period, WECC increased relevant staffing, enhanced relevant processes and procedures, and strengthened metrics to help ensure timely mitigation plan and completed mitigation plan processing. These actions were taken to address certain concerns regarding WECC's mitigation plan processing that were identified in a 2010 FERC audit report.[142] Specifically, WECC created two SME teams, one to review mitigation plans associated with violations of the CIP Reliability Standards, and the other to review mitigation plans associated with Operations and Planning Reliability Standards. WECC also implemented several internal process improvements, including establishing a priority review process for mitigation plans associated with violations posing a high risk to reliability or otherwise requiring prompt attention. WECC now tracks its mitigation plan review efficiency through the use of an internally-developed metric.

WECC has strengthened its active monitoring of mitigation plans by increasing its communication with registered entities. These increased efforts began in 2013. WECC now issues email reminder notices to registered entities as due dates approach. WECC staff also continue to communicate with and give presentations to registered entities regarding best practices for submitting and managing information associated with self-reports, self-certifications, and mitigation plans. WECC now accepts mitigating activities in lieu of a formal mitigation plan for a limited number of cases.

As demonstrated in the table below, WECC has made substantial progress in ensuring that violations from 2007 through 2009 have been mitigated. Only about 11 violations from 2010 and 2011 remained to be mitigated by the end of the assessment period.

[142] *See Order Approving Audit Report, Determining Issue of Separation of Functions, and Directing Compliance and Other Corrective Actions*, 132 FERC ¶ 61,149 (Aug. 10, 2010) at Appendix A.

WECC: Status of Mitigating Activity for Violations Discovered from 2007-2013 and Requiring Mitigation as of December 31, 2013[143]

Year of Discovery	% Completed	% in Progress
2013	56.6%	43.4%
2012	92.0%	8.0%
2011	98.5%	1.5%
2010	98.7%	1.3%
2009	100.0%	0.0%
2008	100.0%	0.0%
2007	100.0%	0.0%
Grand Total	**93.2%**	**6.8%**

WECC has made progress in ensuring that newer violations have been mitigated, with over half of violations discovered in 2013 having completed mitigation by the end of the year. NERC will continue to work with WECC to ensure that all violations are mitigated in a timely manner.

iii. Promoting Reliability through Enforcement Philosophy and Practices

WECC's enforcement philosophy is to use the enforcement process as a tool to influence and encourage desired behavior by registered entities. To that end, WECC Enforcement has adopted risk-based processes and projects that it believes will promote, foster, and influence a reliable BPS. WECC Enforcement seeks opportunities to work collaboratively with and educate registered entities in the enforcement space. WECC Enforcement also recognizes its obligation to ensure fair and reasonable outcomes.

WECC created a new violation assessment process to improve its ability to assess the impact and the root cause of violations, and to determine effective solutions to address the root causes. WECC calls this process a Violation Risk Assessment Methodology (vRAM). This framework is used to assist WECC Enforcement staff in determining the risk posed by a violation, as well as the level of resource allocation that must be dedicated to each violation. During a violation review, WECC Enforcement staff use a four-step process to assess the risk of each violation. This process consists of a severity analysis, controls analysis, likelihood analysis, and risk analysis. This new risk characterization allows a more granular reflection of the risk. In addition, this process considers an entity's connectivity, internal controls, and functions when determining the severity of a violation. WECC believes that this process helps WECC process lesser-risk violations more quickly than in the past.

In its settlement processes, WECC has worked with registered entities, where appropriate, to agree to the future completion of certain activities above-and-beyond those required to ensure

[143] This table reports the percentage of violations discovered from the years 2007 through 2013 with completed or open mitigation. This table excludes dismissed violations and non-U.S. violations.

compliance with one or more Reliability Standards in lieu of the full monetary penalties permitted by the NERC *Sanction Guidelines*. These efforts allow registered entities to allocate their resources to those projects that can increase overall reliability and reduce the likelihood of future noncompliance.

As an example of above-and-beyond activities, registered entities in the WECC region have committed to implement improvements to enhance their ability to comply with Reliability Standards. Examples of compliance-related improvements included developing a process to mitigate violations in a timely manner, implementing meetings and programs to increase awareness of compliance issues, and developing processes to identify the full scope of violations promptly. NERC encourages WECC to continue deploying solutions such as these that promote reliability and insight into processes that can manage risk.

d. WECC's Implementation of Various Aspects of the CMEP

As noted in §II.D.1.a above, NERC conducts ongoing oversight activities to evaluate the effectiveness of each Regional Entity's implementation of the CMEP. These activities include regular reviews and periodic spot checks of specific Regional Entity processes. NERC's oversight activities give NERC an ongoing view into how effectively and efficiently the Regional Entity is executing its enforcement responsibilities. Below is a summary of some of NERC's more recent oversight activities specific to WECC.

With respect to the assessment of monetary penalties, WECC tracks and reviews penalty information to ensure that penalties are applied consistently. Responsibility for penalty tracking analysis lies with WECC's compliance enforcement case management team, which works with WECC management to determine appropriate penalties. NERC reviews all penalties submitted by WECC for appropriateness and consistency with monetary penalties assessed by WECC and other Regional Entities for violations of the same Reliability Standards and requirements occurring under similar facts and circumstances. NERC has found that WECC assesses monetary penalties that are appropriate and consistent with penalties assessed for similar violations.

Based on a spot check, NERC determined that WECC dismisses violations for appropriate reasons. NERC identified opportunities where WECC could improve its letters of dismissal and communicated those opportunities to WECC. By implementing these improvements, WECC can improve the quality of its compliance guidance to registered entities.

As part of its ongoing FFT review processes, NERC reviewed a sample of WECC FFT issues filed or posted during the assessment period to examine WECC's procedures for FFT processing and the application of those procedures to the FFT issues in its caseload. Following its review, NERC concluded that WECC's procedures generally followed FFT requirements and guidance. NERC noted that WECC's Notice of FFT Treatment was very useful and included details on the factors WECC considers, such as the description of the issue, risk statement, and mitigating activities, when considering whether to afford FFT treatment. The WECC sample set contained several instructive examples where the risk statement adequately addressed the issue and the minimal risk to the reliability of the BPS. NERC noted several ways that WECC could

improve its FFT postings and related documentation to provide additional transparency to its determinations.

e. Conclusion

Based on NERC's review of the factors described above, NERC concludes that WECC has performed as an effective Regional Entity with respect to enforcement activities during the assessment period. WECC should adopt the recommendations for improvement provided through NERC's ongoing oversight activities.

III. RELIABILITY ASSESSMENTS

A. Overview of Regional Entity Responsibilities

One of the ERO's responsibilities, as set forth in §215(g) of the FPA, 16 U.S.C. §824o(g), and 18 C.F.R. §39.11, is to conduct periodic assessments of the reliability and adequacy of the BPS in North America.[144] These assessments are conducted by the NERC Reliability Assessment and Performance Analysis (RAPA) department. Pursuant to the RDAs, the Regional Entities help to assess reliability and to provide performance assessment and event analysis of the BPS in their footprints.[145] Section 804 of the NERC ROP specifies that the Regional Entities are to provide data and information to support NERC's annual long-term and seasonal assessments of the reliability of the BPS and any special reliability assessments. In addition, the Regional Entities are to conduct self-assessments of resource adequacy and transmission constraints within their footprints.

Throughout the assessment period, the Regional Entities have supported the RAPA program area by providing Regional Entity-specific data and information for the development of NERC's seasonal, long-term, probabilistic and special reliability assessments. These continent-wide assessments are developed annually by NERC through ongoing coordination between the RAPA department and the NERC Reliability Assessment Subcommittee (RAS), a subcommittee of the NERC Planning Committee (PC).[146] The assessments are primarily based on information and data submitted by a variety of registered entities within the Regional Entities.[147] Data includes

[144] Section 39.11(b) of the U.S. FERC's regulations provide that: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

[145] Assessment of the Regional Entities' performance in the event analysis function is provided in §IV on Reliability Risk Management, below. This §III is focused on the reliability assessment function.

[146] Information on the Reliability Assessment Subcommittee can be found at: http://www.nerc.com/comm/PC/Pages/Reliability-Assessment-Subcommittee-(RAS)-2013.aspx.

[147] Prior to 2011, data was collected and presented based on the political boundaries of each Regional Entity. Following approval by the NERC PC, assessment areas were introduced in 2011. These assessment areas were based on planning coordinator boundaries (or groups of planning coordinators), which more accurately reflect the planning and operational activities of the BPS. The eight Regional Entities are still responsible for providing reliability assessment data to NERC, but data is collected on an assessment area basis.

peak load (demand) forecasts, projected availability of capacity and demand-side management (DSM) resources, and existing and future transmission.[148]

The Regional Entities provide technical input to support the objectives of the RAPA department through the following ERO committees, subcommittees, and working groups:

- PC: The PC is a stakeholder committee chartered by the NERC Board to proactively support the ERO Enterprise mission[149] and associated NERC program areas by carrying out a broad array of technical activities and responsibilities focused on the reliable planning and assessment of the interconnected BPS of North America. The PC's mission is to promote the reliability of the interconnected BPS in North America and to assess and encourage resource and transmission adequacy. The PC also provides a forum where industry representatives and subject matter experts can address reliability, planning and adequacy issues. The PC supports NERC's reliability mission by executing the policies, directives, and assignments from the NERC Board and by advising the NERC Board on matters related to bulk electric system transmission planning, reliability, and resource adequacy.

- RAS: The RAS reviews, assesses, and reports on the overall reliability (adequacy and security) of existing and planned BPS. Six meetings are held annually to support the peer review and information verification necessary for the development of seasonal, long-term, and probabilistic (biennial) assessments. These peer reviews ensure that each assessment area conforms to its own planning criteria, guides and the applicable NERC Reliability Standards. The RAS reports directly to the NERC PC.

- Performance Analysis Subcommittee (PAS): The PAS provides input to and supports the objectives of the NERC RAPA department. The PAS reviews, assesses, and reports on the state of reliability based on historical performance of BPS. The key findings and recommendations of the PAS serve as technical input to NERC's Reliability Standards and project prioritization, compliance process improvements, reliability assessments, event analysis, and CIP, and ultimately support the *State of Reliability* report.

- Reliability Assessment Data Working Group (RADWG): The RADWG (formerly known as the Data Coordination Working Group), operates at the direction of the RAS. The primary function of the RADWG is to facilitate existing data collection

[148] Additional information about the assessment development process is provided in *NERC Reliability Assessment Guidebook*, version 3.1 (NERC Guidebook), available at: http://www.nerc.com/pa/RAPA/rg/ReliabilityGuidelines/Reliability_Assess_Guidebook_3_1Final.pdf.

[149] The ERO's mission is to ensure the reliability of the North American BPS. NERC achieves this mission by facilitating: industry awareness and management of risks to reliability; developing clear, reliability-focused standards; providing reliability assurance and excellence; assessing reliability performance; identifying and improving reliability models; and providing firm and fair enforcement of compliance with mandatory Reliability Standards.

efforts of the Regional Entities for NERC's seasonal and long-term reliability assessments. Additionally, this working group provides a platform for collaborative enhancements of current data collection processes to improve the accuracy, consistency, transparency, and efficiency of NERC's reliability assessment processes. Finally, the RADWG collaborates with the Department of Energy Energy Information Administration and other governmental/regulatory agencies that conduct similar data collection efforts. The goal of the RADWG is to reduce duplicative reporting requirements while promoting consistent data definitions.

B. Regional Entity Responsibilities in the Preparation of Assessment Reports

NERC annually prepares two seasonal (summer and winter), one long-term (10-year), and one probabilistic (biennial) assessment under the direction of NERC's PC and with support from the RAS. To support these assessments, each Regional Entity conducts reliability assessments for its footprint (assessment area, as described above) in accordance with guidelines provided in the NERC Guidebook. The NERC Guidebook is a "living document" which aims to improve consistency and transparency, to enhance granularity, and to establish a core framework for conducting independent assessments. While inherent differences in the way that the BPS is planned and operated across North America result in different approaches in conducting reliability assessments, NERC maintains a consistent framework for how the BPS is assessed in different areas. This framework includes a common set of definitions and measures for demand, resources, transfers, transmission, and resource adequacy.

Ongoing coordination between NERC and the Regional Entities occurs throughout the assessment development process. This is accomplished through monthly calls with each Regional Entity to identify Regional Entity-specific challenges in the collection of assessment data and information.

1. Reliability Assessment Data Collection

NERC collects seasonal and long-term electricity supply and demand data for the assessments areas through the Regional Entities. The data is collected through a series of forms that are developed and distributed by the RAPA department, in coordination with the RAS and RADWG. Specific seasonal and long-term data collected for the reliability assessments include: (i) peak load (demand) forecasts; (ii) on-peak capacity (including DSM); and (iii) transmission facilities. Although these metrics have been collected by NERC since 1968, the level of detail for each metric has grown, especially during the last decade. The data collection activities for each assessment require ongoing coordination between NERC and the Regional Entities. This coordination is executed through the RADWG and RAS to ensure that the data are accurate and consistently reported at the assessment area level.

The underlying data collection processes and planning methods also vary by assessment area or Regional Entity. These variances exist due to the inherent complexity, different corporate structures and unique history of the industry. More importantly, different attributes within each assessment area (e.g., climate, resource mix, market structures) require Regional Entity-specific or assessment area-specific planning considerations. These issues are identified and addressed

through the RAS and RADWG. More recently, in 2012, NERC's RAPA department instituted the development of individual Methods and Assumptions reports[150] for the long-term, seasonal, and probabilistic assessments. These reports, updated annually, provide detailed documentation of the planning activities and special considerations applicable to each assessment area or Regional Entity and ensure consistency across all Regional Entities.

2. Reliability Assessment Narratives

NERC's seasonal, long-term reliability, and probabilistic assessments include information from each assessment area (or Regional Entity if prior to 2011). Similar to the data collection process (described above), the NERC RAPA department coordinates the collection of assessment information through the RAS. Specifically, narrative guides (or questionnaires) are developed annually, with RAS input, to assess future resource adequacy and identify potential NERC-wide or Regional Entity-specific reliability issues. Narrative guides for the seasonal, long-term, and probalistic assessments are distributed to each Regional Entity several months prior to the data submittal due date to NERC.

The assessment areas submit their self-assessments (in response to the narrative guides) to NERC through the Regional Entities. Each Regional Entity's self-assessment is then distributed to RAS members from other Regional Entities for an in-depth and comprehensive review of the data and information. Peer reviewer comments are discussed with Regional Entity and assessment area representatives, and refinements and adjustments are made, as needed. The Regional Entity self-assessments are then subjected to scrutiny and review by the entire RAS. This peer review process provides an essential check and balance to ensure the validity of the information provided for each assessment. It also provides a mechanism for the members of the RAS to become fully convinced that each Regional self-assessment is accurate, thorough, and complete. Regional Entity representatives are able to examine and better understand planning methods and assumptions in other Regional Entities while also critiquing these processes or identifying potential gaps or shortfalls. Finally, the peer review also ensures consistency of methods and assumptions so that reliability evaluations are uniform.

Following the peer review process, the NERC RAPA compiles all Regional self-assessments into a single draft report, which is reviewed by the NERC Operating Committee (OC), the Member Representatives Committee (MRC), and NERC senior management. The report ultimately requires NERC PC approval before it is submitted to the NERC Board for final approval. This comprehensive vetting process promotes the development of independent assessments with heavy coordination among Regional Entity stakeholders.

C. Regional Entity Responsibilities in the Preparation of *State of Reliability* Reports

NERC annually produces a *State of Reliability* report that provides NERC's independent view of ongoing BPS trends to objectively present an integrated view of reliability performance. The key findings and recommendations serve as technical input to NERC's processes for risk assessment, Reliability Standards projects prioritization, compliance process improvements, event

[150] Methods and Assumptions reports are available at: http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

analysis, and CIP activities. The analysis of BPS performance developed as part of the report provides an industry reference of historical reliability, offers analytical insights regarding industry action, and enables the identification and prioritization of specific steps that can be taken to manage risks to reliability. The data that are analyzed to produce the *State of Reliability* report are submitted by entities across North America. Each Regional Entity is responsible for reviewing the data submitted by entities in its respective region for completeness and accuracy. Once this review is complete, the Regional Entity staff informs NERC staff that the data are ready for analysis.

D. Regional Entity Responsibilities in the Collection of Data for NERC Reliability Databases

The NERC Board has approved mandatory data reporting concerning conventional generating units, transmission outages, and demand response availability. NERC collects this data using its Generating Availability Data System (GADS), Transmission Availability Data System (TADS), and Demand Response Availability Data System (DADS) databases. This unique series of databases is used to collect, record, and retrieve operating information tracking, reporting, analyzing, and improving the reliability performance of the BPS. Regional Entity staff work with NERC staff to ensure the data submitted by entities is timely, complete, and accurate.

E. Regional Entity Resources Budgeted for Reliability Assessment and Performance Analysis During the Assessment Period

During the assessment period, each Regional Entity increased its budgeted direct expenses and its budgeted FTE staffing for its RAPA program. The following table shows the amounts of direct expense budgeted by each Regional Entity for its RAPA program in its 2009 and 2014 business plans and budgets as filed with the Commission:[151]

Regional Entity	2009 Budget	2014 Budget	Percent Increase
FRCC	$918,744	$1,270,439	38.3%
MRO	$982,029	$1,329,480	35.4%
NPCC	$1,446,942	$1,888,972	30.5%
RFC	$985,605	$2,213,282	124.6%
SERC	$976,109	$1,398,882	43.3%
SPP RE	$432,558	$1,345,065	211.0%
Texas RE	$365,180	$1,055,983	189.2%
WECC	$2,742,063	$6,516,514	137.7%

The following table shows the direct FTE staffing budgeted by each Regional Entity for its RAPA program in its 2009 and 2014 business plan and budget as filed with the Commission:

[151] WECC amounts include spending to perform work under DOE grants.

Regional Entity	2009 Budget	2014 Budget	Percent Increase
FRCC	3.67	5.29	44.1%
MRO	4.75	6.49	36.6%
NPCC	3.90	5.83	49.5%
RFC	5.50	10.00	81.8%
SERC	4.50	7.60	68.9%
SPP RE	3.40	7.13	109.7%
Texas RE	2.20	4.75	115.9%
WECC	14.00	23.60	68.6%

F. Evaluation of Regional Entity Performance in Reliability Assessment Activities and Areas for Improvement

As the discussion in §§III.B, C, and D above makes clear, the quality of NERC's reliability assessments depends heavily on the collaborative efforts of the Regional Entities, working through the RAS. The ability of the NERC RAPA staff to identify NERC-wide highlights and key findings is heavily dependent on the submittal of on-time, complete, and accurate data and information from each assessment area and Regional Entity.

NERC has assessed the performance of the Regional Entities during the assessment period against the following criteria pertaining to the Regional Entities' roles and responsibilities:

(1) Regional Entities interface with registered entities to support and assure overall alignment with wide-area, ERO-formulated, reliability assessments and performance analyses, program design and structure, and to undertake support functions for wide-area studies and analyses and the development of specific region-centric assessments initiated by the Regional Entity to gather greater insight into a particular reliability issue.

(2) Regional Entities evaluate and provide seasonal, long-term reliability, and probabilistic assessments of the planning coordinator within their regions (assessment areas) including the data supporting the various analyses and evaluations of anticipated reliability conditions.

(3) Regional Entities compile interconnection-wide, steady-state and dynamic models of the registered entities within their regions that have been developed by the applicable planning coordinators consistent with the program design and structure.

(4) Regional Entities perform the data gathering function for certain performance analysis data efforts, assuring integrity, quality, and timeliness of the underlying data, and using data-gathering quality control procedures, forms and reporting mechanisms provided by NERC.

(5) Regional Entities provide technical resources and expertise in support of strategic plan initiatives, aligning budget and resource process proposals that maximize the efficiency and effectiveness of the overall ERO enterprise on technical, analyses, information technology and program approaches.

(6) Regional Entities manage their technical participation in applicable ERO committees and sub-groups in alignment with overall strategic objectives and the RAPA program structure and design while minimizing duplication and the overlap with SMEs and technical groups.

(7) Regional Entities coordinate with registered entities and provide technical resource support to wide-area analysis of technical issues (oscillations, frequency, modeling, system protection, BES, etc.) that involve joint efforts.

(8) Regional Entities support the development and implementation of major projects and initiatives (e.g., application of the BES definition), process exceptions requests, implement compliance, registration and standards applicability activities, and arrange Regional Entity processes for consistent use within North America.

(9) Regional Entities manage the relationship with registered entities with respect to RAPA program deliverables and objectives, including data and analytic assembly quality, integrity, and timeliness.

(10) Regional Entities collect misoperation data in fulfillment of obligations in PRC-004-2.1a, Requirement R3. The Regional Entities, in conjunction with their respective protection system subcommittees, analyze the data to determine trends and recommendation actions.

Based on its review of the Regional Entities' performance in Reliability Assessment during the assessment period, NERC makes the following observations:

(1) All Regional Entities conduct Reliability Assessments in general accordance with the NERC Guidebook.

(2) NERC supports and collaborates with Regional Entity staff through stakeholder committees to ensure consistent execution of delegated functions. In addition, the Regional Entities directly collaborate and communicate with registered entity personnel when conducting reliability assessments. Together, NERC and the Regional Entities have maintained a common framework for assessing the reliability of the BPS.

(3) Further improvements in data checking and validation processes are needed. Regional Entities are leading and participating in the development of the NERC Reliability Assessment Data System (RADS). While this automated data system is still under development, significant improvements to data collection and validation have already been made at the Regional Entity level to support RADS in 2015.

(4) Each Regional Entity reviews the data submitted by registered entities for completeness and accuracy in TADS, DADS, and GADS. Once the review is complete, the Regional Entity informs NERC that the data is ready for analysis. The Regional Entities have typically met these expectations.

(5) In the future, some Regional Entities may need more resources to support evolving assessment approaches. More granular reliability assessments, which are expected through the course of increased evaluations of high-priority emerging reliability issues, may require additional data and information. This is true particularly in response to a changing resource mix and an evolving electricity grid; different approaches for measuring and evaluating future reliability may be needed. Most reliability assessment data supports the measurement of resource adequacy. To support a comprehensive understanding of essential reliability services, NERC will be considering how other long-term reliability evaluations should occur and what data and information will be needed over the next several years. These efforts, along with further evaluation of environmental regulations, DSM, gas and electric interdependencies, increasing variable generation, and other emerging reliability issues, require strong support from the ERO.

(6) Some Regional Entities rely upon their member entities to perform various technical reviews. In order for Regional Entities to provide an independent review of both BPS performance and future states of reliability, Regional Entities may need increased staff participation. The need for independent review by regional staff will be greater over time given the challenges of the evolving BPS.

Based on its review, NERC makes the following recommendations for improvements:

(1) NERC and the Regional Entities should work collaboratively to develop an ERO enterprise-wide database solution to reinforce the existing structures and processes (including Regional Entity involvement) used to develop NERC assessments. An ERO-wide database solution would allow for consistent data error checking which would ultimately improve the overall efficiency across the ERO and contribute to better reliability assessments.

(2) NERC RAPA department management needs to further work on the best design for managing functional area relationships with the Regional Entities and developing better metrics to evaluate Regional Entity performance.

Going forward, NERC, in collaboration with the Regional Entities, will: (i) develop a comprehensive overarching design and set of controls, reporting requirements, metrics, and feedback mechanisms for reliability assessment activities, including the essential oversight elements listed above; (ii) identify functional qualifications for performance of reliability assessment activities; and (iii) adopt risk-based approaches to monitoring performance of delegated functions and providing effective feedback and coaching to continuously improve overall ERO Enterprise performance.

In conjunction with these improvement efforts, the Regional Entities should (1) continue to support NERC in the development of comprehensive functional program designs and controls (e.g., performance metrics and Regional Entity assessments based on common criteria); and (2) adapt existing Regional Entity programs for reliability assessment activities to conform with emerging program designs provided by NERC (e.g., ERO-enterprise wide data collection and database systems).

Many of the improvement activities described above have been initiated during the latter stages of the assessment period. In October 2013, the ERO Executive Management Group, comprised of senior management from NERC and each Regional Entity, approved a revised ERO-RAPA group charter. The purpose of the revised ERO-RAPA group charter is to provide a forum for Regional Entities and NERC RAPA department staff to collaborate on ongoing activities that are part of the RAPA department's approved roles and responsibility. This group will facilitate the flow of information, jointly coordinate work product expectations (scope, timing, resource expenditures, schedule, etc.) and promote consistency in the final products. The ERO-RAPA group includes a staff person from each of the eight Regional Entities (selected by the Regional Entity) to provide overall coordination of assessment activities with the NERC RAPA staff. Also, the ERO-RAPA group will implement, promote, and provide strategic and tactical guidance for Reliability Assessment activities per the ERO oversight model.

IV. RELIABILITY RISK MANAGEMENT (SITUATION AWARENESS AND EVENT ANALYSIS)

This §IV evaluates the Regional Entities' activities during the assessment period with respect to Reliability Risk Management (RRM). RRM encompasses the program areas of Situation Awareness and Event Analysis.

A. Regional Entity Progress in Identifying and Analyzing System Events and Improving Situation Awareness

Pursuant to the RDAs and the NERC ROPs, NERC and the Regional Entities collaborate to monitor present conditions on the BPS by gathering and assessing situation awareness information from registered entities.[152] The Regional Entities also assist NERC in analyzing major events, off-normal occurrences, BPS performance and BPS vulnerabilities.[153] NERC notes that as a general matter, the Regional Entities have not devoted, and have not been asked to devote, a level of resources to these activities comparable to the resources devoted to compliance monitoring and enforcement and reliability assessment. However, during the assessment period, the Regional Entities as a group made significant progress in executing these duties. The primary, collaborative achievement during this period was the formalization of a voluntary ERO Event Analysis process which facilitates coordinated responses to and review and analysis of system events. As part of the formalization of the Event Analysis process, an event classification system based on event severity was developed and put into effect. During the assessment period, NERC and the Regional Entities began using the event analysis process to analyze events and disseminate lessons learned to all industry members and to Regional Entities.

Prior to formalization of the Event Analysis process, which brought the ERO Event Analysis program to a mature state, the Regional Entities interacted individually with registered entities without a coordinated ERO-wide program for information sharing. In 2010, the Regional Entities initiated a dialogue with registered entities to discuss the requirements for preparing

[152] ROP §1001 (Situation Awareness). The Regional Entities' responsibilities with respect to event analysis and situation awareness are described in §7 of the RDAs.

[153] ROP §§807 (Analysis of Major Events) and 808 (Analysis of Off-Normal Occurences, Bulk Power System Performance, and Bulk Power System Vulnerabilities).

consistently formatted event reports. ReliabilityFirst, for example, developed a series of questions and a list of Reliability Standards that registered entities could use as a guideline as they developed event analysis reports and performed internal compliance reviews.

In June 2010, NERC and the Regional Entities created the NERC Event Analysis Working Group (EAWG), which included members from every Regional Entity. The EAWG expended significant efforts to develop an ERO Event Analysis process document in coordination with industry stakeholders for use across North America. On October 25, 2010, personnel from NERC, the Regional Entities, and the EAWG commenced a field trial of the ERO Event Analysis process, and conducted a comprehensive evaluation of the field trial data. Industry engagement in the field trials was noteworthy. Using the extensive feedback received from registered entities during the field trials, the EAWG developed version 1 of the *ERO Event Analysis Process*, which went into effect on February 21, 2012.[154] In June 2012, the NERC OC approved version 2 of the *ERO Event Analysis Process*, and the EAWG was transitioned to the NERC Event Analysis Subcommittee (EAS). By integrating industry engagement and the collaborative review of disturbances into the ERO Event Analysis process, the EAWG improved the effectiveness, predictability, consistency, and timeliness of the ERO Event Analysis program. The EAWG has since been elevated from a working group to a subcommittee under the NERC OC. Regional Entity staff continue to actively participate in the implementation and improvement of the ERO Event Analysis program. Since October 2010, registered entities have submitted more than 325 event reports through the ERO Event Analysis program. Several lessons learned have already been shared with the industry as a result of the ERO Event Analysis program.

The ERO Event Analysis program facilitates the sharing of lessons learned from applicable system events and trends. This sharing of lessons learned provides benefits to industry in terms of enhanced reliability. The new process provides a mechanism for registered entities to complete a preliminary event report for events occurring on their system. The higher the category of the system event (based on the event classification system), the more detailed analysis the registered entity is expected to perform and to share with the Regional Entity and NERC.

During the assessment period, a major test of the Regional Entities' progress in situation awareness and event analysis occurred in connection with the February 2011 Southwest Cold Weather Event, which affected areas of New Mexico, Arizona, and Texas and was the first major Category 4 Event to occur after the current ERO Event Analysis process was put in place. Approximately 1.3 million electric customers were out of service at the peak of this event. NERC, the Commission, and the Regional Entities whose areas were affected jointly analyzed the Southwest Cold Weather Event, conducted an assessment of previous severe winter events, published lessons learned, distributed training materials, and hosted an informational webinar to help industry members prepare for future severe cold weather events. As a result of the experience with this event, the ERO Event Analysis program was enhanced.

In addition to executing the Event Analysis process upon the occurrence of significant system events, the Regional Entities support NERC's situation awareness efforts by providing

[154] *See* the Event Analysis Program web page, available at: http://www.nerc.com/pa/rrm/ea/Pages/EA-Program.aspx.

more detailed information on occurrences of interest,[155] making initial notifications of certain Regional Entity-specific occurrences, and participating in daily situation awareness conference calls and weekly event analysis meetings. The Regional Entities also code all events and present them in monthly discussions with NERC.

NERC and the Regional Entities are continuously refining the ERO Event Analysis process based on experience and as system conditions change. For example, in 2013, NERC began focusing on energy management system (EMS) outages and their impact on BPS reliability. This focus on EMS outages has resulted in the publication and dissemination of two NERC Advisories pursuant to NERC ROP §810 as well as multiple lessons learned. NERC and the Regional Entities also conducted a monitoring and situation awareness workshop in September 2013 to share the lessons learned and the good industry practices learned from this work.

An added benefit of the ERO Event Analysis process is that it has driven a significant decrease in the initiation of formal compliance investigations by NERC and the Regional Entities. The responsiveness of registered entities in providing more extensive information about BPS disturbances has enabled NERC and the Regional Entities to perform more complete compliance assessments of these occurrences, without the use of a formal compliance monitoring method.

B. Hurricane Sandy Provided a Meaningful Case Study and Test of the ERO's Situation Awareness Capabilities

During the assessment period, in late October 2012, Hurricane Sandy provided a major test of the abilities of NERC, the Regional Entities, and the registered entities to engage in large-scale situation awareness and information sharing activities during a major system event. The hurricane made landfall on the Eastern Seaboard on October 29, 2012, and caused massive disruptions to the electric power system in New York, New England, and the Mid-Atlantic states. Over the course of the event, 20,007 MW of generation capacity was rendered unavailable and the distribution system was severely damaged. Approximately 8.35 million electric customer outages were reported across the impacted area.

In preparation for Hurricane Sandy, the Regional Entities and registered entities assisted NERC in monitoring conditions on the BPS and in responding to events as necessary. For example, ReliabilityFirst, NPCC, SERC, the New York Independent System Operator, ISO New England (ISO-NE), and PJM Interconnection, in conjunction with NERC's situation awareness team, coordinated storm preparation plans with the transmission owners, generation owners, balancing authorities, and other registered entities within the area forecasted to be impacted. Entities worked to ensure that sufficient numbers of additional field operation crews were scheduled and available to respond to the expected storm-related disruptions. Where possible, previously scheduled outages were postponed to ensure that facilities would be available over the next several days. Generators were advised of expectations during the storm, which included the potential for abnormal dispatch instructions. Blackstart units were also contacted to confirm that the units had sufficient fuel available to run for an extended duration.

[155] Many of these occurrences do not rise to the level of a reportable event within the ERO Event Analysis program.

A day before the hurricane made landfall, NPCC initiated a series of daily coordination conference calls. During these calls, the reliability coordinators in NPCC shared reported current and projected system status and operational challenges. These regional conference calls were an important means of monitoring and communicating events with adjacent reliability coordinators, and they continued daily throughout the storm and during the ensuing recovery efforts. In addition, gas pipelines were contacted and requested to advise ISO-NE of any special procedures or anticipated abnormal conditions in light of the impending storm. All gas pipelines implemented their hurricane preparedness plans for the Northeast region, which included checking on-site generators for compressor stations and reviewing staffing plans and facility flood plans.

Registered entities convened or participated in numerous conference calls and broadcasts. They also communicated with the mutual assistance groups to which they belonged. These calls began on October 27, 2012, and continued through the restoration effort, with some lasting though November 9, 2012. Following the storm, NPCC, ReliabilityFirst and SERC, whose footprints include the areas directly impacted by the storm, participated in a joint effort with NERC to provide an overview of the impact of Hurricane Sandy on the interconnected BPS and gather lessons learned for storm preparation and restoration. The results of this effort are included in the *Hurricane Sandy Event Analysis Report* published by NERC in April 2014.[156]

Other Regional Entities have had the opportunity to exercise their situation awareness and information sharing processes and to demonstrate their proficiency, but not at the level that was required during Hurricane Sandy. FRCC, SERC, and SPP RE demonstrated their situation awareness processes and proficiency during Hurricane Isaac in September, 2012. ReliabilityFirst demonstrated its situation awareness processes and proficiency during the Derecho storm response in June through July 2012. Finally, WECC demonstrated its situation awareness processes and proficiency during multiple wildfires that caused transmission system disturbances in the Spring of 2013. While all of these events were smaller in scale and impact than Hurricane Sandy, the general processes used by the Regional Entities were the same and in each instance they were successfully executed.

C. Areas for Future Improvement and Enhancements

The EAS of the NERC OC conducts an annual review of the ERO Event Analysis process. The OC receives comments from industry members on the ERO Event Analysis process and gives these comments full consideration during the annual review. Some commenters have suggested that communication and coordination between the parties involved in event analysis should be further enhanced. Examples of suggested improvements include increasing the timeliness, transparency and comprehensiveness of dissemination of information relating to event analysis and lessons learned, and streamlining the cause coding mechanism. In response, NERC is exploring the possibility of implementing enterprise information technology systems to provide efficiencies in event analysis and related reporting processes.

[156] Available at: http://www.nerc.com/pa/rrm/ea/Oct2012HurricanSandyEvntAnlyssRprtDL/Hurricane_Sandy_EAR_20140312_Final.pdf.

V. BUSINESS PLANNING AND BUDGETING, FINANCE AND ACCOUNTING

A. Provisions of Commission Orders, the RDAs and the ROP Concerning the Regional Entities' Business Plans and Budgets and Financial Accounting and Reporting

The Commission's regulations at 18 C.F.R. §39.4(b) require that the ERO's annual business plan and budget submission include "the entire annual budget for statutory and non-statutory activities for each Regional Entity, with supporting materials, including . . . each Regional Entity's complete business plan and organization chart, explaining . . . the proposed expenditure of funds collected in sufficient detail to justify the requested funding collection and budget expenditures . . . ." The regulation further specifies that the ERO's annual budget submission "shall include the line item budgets for the activities of each Regional Entity that are delegated or assigned to each Regional Entity pursuant to §39.8." Further, in Order No. 672, the Commission stated that "The ERO must determine, at a minimum, whether each Regional Entity's proposed budget is adequate to carry out the functions delegated to it." [157]

The RDAs specify that the Regional Entity and NERC shall develop, through a collaborative process, an annual business plan and budget, in accordance with the Commission's regulations and orders and NERC business planning and budgeting policies and instructions.[158] The Regional Entity's business plan and budget is to describe the activities necessary for, and provide a budget with adequate resources for, the Regional Entity to carry out its delegated activities under the RDA. The business plan and budget is also required to show the funding sources and amounts to fund the proposed budget, including, as applicable, assessments to end users, penalty monies and other sources of funds. The RDAs further provide that NERC is to provide the Regional Entity with the form or forms, and accompanying instructions, for submittal of the Regional Entity's business plan and budget. NERC and the Regional Entities are to develop an annual schedule for preparation of the business plan and budget, and each Regional Entity is to submit its proposed annual business plan and budget for carrying out its delegated authority functions and related activities in accordance with the schedule. These RDA provisions are also reflected in §§1103 and 1104 of the NERC ROP.

Additionally, the RDAs specify that NERC shall develop, in consultation with the Regional Entities, a reasonable and consistent system of accounts, with a level of detail and record keeping comparable to the Commission's Uniform System of Accounts and sufficient to allow the Commission to compare the Regional Entity's approved budget with actual results for the year.[159] The Regional Entity must follow NERC's prescribed system of accounts except where a departure is specifically allowed by NERC. Further, the RDAs require the Regional Entities to submit to NERC (i) unaudited quarterly interim financial statements, in a form provided by NERC, no later than 20 days after the end of each fiscal quarter, and (ii) audited annual financial statements,

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[157] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006), at P 229.

[158] The RDA provisions described in this paragraph are generally found in §9 of each RDA.

[159] This provision is also specified in NERC ROP §1103.4 (NERC Budget Development).

including supporting materials, in a form provided by NERC, no later than May 1 of the following year.

The Commission has also required NERC and the Regional Entities to file annual comparisons of each entity's budget to actual results for the year. These reports (sometimes referred to as "true-up reports") are to be filed on or before May 30 of the following year. The Commission originally imposed this requirement in its order accepting the NERC and Regional Entity business plans and budgets for the year 2008,[160] and clarified the requirements for this filing in several subsequent orders. The filings are to provide a comparison of the NERC and Regional Entity budgets to actual costs incurred in the preceding year, "in sufficient detail and with sufficient explanations for the Commission to determine, by program area, the reasons for deviations from the budget and the impacts of those deviations."[161] In an order issued in June 2008, the Commission provided additional direction concerning the required contents of the Regional Entities' annual true-up reports:

> 37. To promote consistency and transparency, the Commission directs the use of certain practices and formats in future true-up filings. In particular, Regional Entities must provide a cover letter discussing major areas of actual cost-to-budget variances for all of the Regional Entity's statutory programs in the aggregate. Regional Entities should also follow NERC's template for the presentation of actual costs and budgeted costs on a program-by-program and line-item basis. Significant variances must be explained on a line-item basis with enough particularized information to clearly support each such variance. Regional Entities should refrain from using generic, program area summaries to support significant variances. The cause for each such variance should therefore be clear on its face. Further, each Regional Entity must provide an explanation of the allocation methods it used to allocate indirect costs to the direct statutory program or functional areas, as well as any allocation between any statutory and non-statutory activities.[162]

In addition, the Commission directed that in the annual true-up reports, NERC and the Regional Entities should justify any use of cash reserves as variances.[163]

B. Regional Entity Performance in Business Planning and Budgeting, Accounting, and True-Up Reporting

Throughout the assessment period, consistent with the provisions of the Commission's regulations and orders, the RDAs, and the ROP summarized above, NERC and the Regional Entities have collaboratively developed annual business plans and budgets for each year 2010 through 2014 which describe the activities and resources necessary to execute the Regional

[160] *North American Electric Reliability Corporation, Order Conditionally Accepting 2008 Business Plan and Budget of the North American Electric Reliability Corporation and Ordering Compliance Filings*, 121 FERC ¶ 61,057 (2007).

[161] *Id*. at P 23. In addition, any use of statutory funds for non-statutory activities is to be identified and an explanation provided as to how the statutory funds will be reimbursed. *Id*. at P 66.

[162] *North American Electric Reliability Corporation, Order Conditionally Accepting Compliance Filing*, 123 FERC ¶61,282 (2008), at P 37.

[163] *Id.* at P 38.

Entities' delegated authority functions and related activities. Overall, the Regional Entities have performed their responsibilities in the business planning and budgeting process in accordance with the requirements of the Commission's regulations and orders, the RDAs and the NERC ROPs. In a sense, the five-year evaluation of the Regional Entities' performance in business planning and budgeting, accounting and true-up reporting can be considered redundant because NERC and the Regional Entities engage in these activities on an annual basis (or more frequent basis for some aspects of financial reporting), which provides NERC with continuous opportunities to review each Regional Entity's performance of these functions and its compliance with procedures and requirements, and to identify and correct any deviations or deficiencies. Further, the Commission's annual review and acceptance of each Regional Entity's business plan and budget and true-up report provides an ultimate check on the Regional Entity's performance.

To provide ongoing, collaborative oversight of the business planning and budgeting and accounting and financial reporting processes, NERC and the Regional Entities have formed an ERO Finance Group comprised of representatives of NERC and each Regional Entity. The purpose of the group is to: (i) facilitate the coordination, preparation, review and approval by NERC and the Commission of the NERC and Regional Entity business plans and budgets consistent with the requirements of the NERC ROP, the RDAs, any specific requirements established by the NERC Finance and Audit Committee or Board, and applicable statutory, governmental and regulatory requirements; (ii) facilitate the coordination, preparation, review and filing of the NERC and Regional Entity business plans and budgets with Canadian and, to the extent applicable, other governmental and regulatory authorities consistent with applicable governmental and regulatory requirements; (iii) collaborate and support initiatives to improve the cost effectiveness and efficiency of NERC and Regional Entity operations; and (iv) provide general support to the NERC and Regional Entity executive leadership regarding such other finance and accounting matters as may from time to be deemed necessary.

Since NERC became the ERO, NERC and the Regional Entities have continuously striven for consistency and improved transparency and detail in the annual NERC and Regional Entity business plans and budgets. The ERO Enterprise business planning and budgeting processes matured significantly during the assessment period. During this period, the ERO Enterprise implemented numerous process improvements in the areas of business and resource planning, allocation and budgeting. In the development of the 2010 business plans and budgets, in particular, a number of significant improvements were adopted. NERC believes that in the preparation of the 2012 business plans and budgets, a mature, steady state was reached with respect to process, format and content. This steady state has been maintained in the development of the 2013 and 2014 business plans and budgets and the currently ongoing development of the 2015 business plans and budgets (which will be completed outside of the assessment period). A partial list of steps that have been taken to achieve consistency, transparency and appropriate levels of detail includes the following:

(1) Development, adoption and use of a common, consistent chart of accounts by all entities and the presentation of budget and financial information in accordance with the accounting system;

(2) Development and use of a consistent organization and format for the business plans and budgets and the annual true-up reports, including a common table of contents,

common and consistent information, and common and consistent format for tables and charts providing the Regional Entity's funding, budget, actual costs, and staffing information;

(3) Development and use of a common definition of administrative (indirect) costs and consistent methodologies for identifying budgeted and actual expenses as "direct" or "indirect" expenses;

(4) Development and use of a consistent methodology for allocating indirect expenses to the direct program budgets;

(5) Development and use of a consistent policy for capitalizing vs. expensing expenditures;

(6) Collaborative development, on an annual basis, of a set of detailed shared (common) business planning and budgeting assumptions to be used by NERC and each Regional Entity in preparing their individual business plans and budgets. In recent budget preparation cycles, these assumptions have been expanded from a one-year set of assumptions to a three-year set of assumptions;

(7) Development of a common set of budget metrics for each Regional Entity to present in the annual business plan and budget filings; and

(8) Introduction of a three-year budget forecast into NERC's and each Regional Entity's annual business plan and budget.

In addition, NERC and the Regional Entities jointly develop a three-year rolling *ERO Enterprise Strategic Plan* which includes goals, objectives and deliverables over the planning period and is used in the development of each entity's business plan and budget. The development and implementation of these common formats and methodologies has helped to continuously improve the efficiency of the business plan and budget preparation process and enabled NERC and Regional Entity financial and accounting staffs and senior management to devote greater attention to more substantive budget issues.

In accordance with the RDA provisions described earlier, NERC and the Regional Entities establish and publish, for each annual budget preparation cycle, a detailed schedule for preparation, review, and approval of the business plans and budgets. The annual business planning and budgeting process for a year typically begins late in the second preceding year or early in the preceding year. The schedule provides for posting of initial and revised drafts, and periods for receipt of stakeholder comments, leading up to the ultimate approval of the business plans and budgets by the NERC Board at its August meeting and filing of the business plans and budgets with the Commission by on or about August 23 as required by the Commission's regulation. In addition, each Regional Entity goes through a posting and stakeholder review and comment process for its membership and other interested parties prior to approval of its business plan and budget by its governing body for submission to NERC. In its business plan and budget filing with the Commission, NERC provides descriptions of each Regional Entity's internal process. Over the assessment period, NERC and the Regional Entities have significantly increased the

transparency of the business plan and budgeting process, by providing numerous opportunities for stakeholder input and feedback prior to Regional Entity board and NERC Board approval and submittal to the Commission.

NERC's oversight of the Regional Entities' business plan and budget preparation, leading up to approval of the Regional Entities' business plans and budgets, is generally focused on the following areas:

(1) An assessment of the adequacy of the Regional Entities' resources and activities being budgeted by the Regional Entity to perform delegated functions.

(2) A review of the alignment of the Regional Entity's goals, objectives and major activities to the *ERO Enterprise Strategic Plan*.

(3) A review of the quality and completeness of the financial information presented by the Regional Entities, including:

  (a) Conformance with the Commission's budget reporting requirements;

  (b) Separation of statutory and non-statutory activities;

  (c) Supporting detail for projections; and

  (d) Working capital and operating reserve budgets, projections, policies and controls.

(4) A review of the Regional Entities' efforts to improve efficiency and control costs.

Throughout the budget review process, where appropriate, NERC requests additional information and recommends changes. As needed, NERC and Regional Entity management and finance staffs convene meetings and conference calls to provide feedback and to refine their respective business plans and budgets. In addition to reviewing and providing feedback to the Regional Entities, NERC management considers other relevant information when reviewing the Regional Entity budgets, such as the findings and recommendations contained in the audits the Commission has conducted of NERC and the Regional Entities.

During the assessment period, the Regional Entities also performed in accordance with requirements with respect to financial reporting, including the preparation of the annual true-up reports. During the assessment period, NERC and the Regional Entities have significantly increased the transparency and content of quarterly and year-end actual-to-budget variance reporting to the Finance and Audit Committee of the NERC Board. In general, the Regional Entities have consistently submitted their unaudited quarterly financial reports on a timely basis as required by the RDAs. With respect to the annual true-up reports, NERC and the Regional Entities developed a common, consistent format for these reports complying with the Commission's directives. The format consists of: (i) a cover letter identifying major areas of actual cost to budget variance for each program and providing the other information specified by Commission orders (e.g., whether any statutory funds were used for non-statutory activities, the Regional Entity's use of cash reserves and change in its working capital position); (ii) tables comparing on a line-item basis actual to budgeted expenditures on a total statutory basis and (if the Regional Entity also has non-statutory activities) total company basis; and (iii) tables

comparing on a line-item basis actual to budgeted expenditures for each of the Regional Entity's direct statutory programs and its administrative (indirect) programs, with narrative explanations provided for line-item variances that exceed $10,000 and 10% of budget. In general, the Regional Entities have submitted their audited annual financial reports and their draft true-up reports to NERC on a timely basis to allow for NERC to review and provide any feedback and the reports to be filed with the Commission by the May 30 deadline. In addition, NERC and the Regional Entities have developed a set of administrative cost metrics to be presented to the Commission as part of the annual true-up report filing.

FEDERAL ENERGY REGULATORY COMMISSION
DOCKET NO. RR14-___

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

ATTACHMENT 4

TO

FIVE-YEAR ELECTRIC RELIABILITY ORGANIZATION PERFORMANCE ASSESSMENT REPORT

NERC CONSIDERATION OF INDUSTRY FEEDBACK

JULY 21, 2014

Attachment 4

This Attachment presents information from the stakeholder survey that the North American Electric Reliability Corporation (NERC) conducted in October 2013 for purposes of the *Five-Year Electric Reliability Organization (ERO) Performance Assessment Report*, and from stakeholder comments received on postings of drafts of the *Five-Year ERO Performance Assessment Report*. This Attachment includes tables summarizing key comments received from stakeholders and NERC's responses to those comments, including identifying where in the *Five-Year ERO Performance Assessment Report* the comment is addressed.

This Attachment also includes summary information on the responses to the questions posed in the stakeholder survey and the type and distribution of the respondents. The stakeholder survey requested comments on the following broad categories of the ERO Enterprise's activities:

(1) Reliability Standards

(2) Compliance Operations

(3) Enforcement

(4) Registration and Certification

(5) Reliability Assessment & Performance Analysis Metrics

(6) Training, Education, and Personnel Certification

(7) Event Analysis

(8) Critical Infrastructure Protection

(9) Stakeholder Communications, Public Relations, and IT

(10) Business Plan and Budget

(11) Independence and Stakeholder Input

Table 1: Stakeholder Comments Concerning NERC

In the following table, (i) the first column contains summaries of key stakeholder comments; and (ii) the second column lists a brief response to an individual comment and, where applicable, the specific location(s) where the comment is addressed within the *Five-Year ERO Performance Assessment Report*. The table is divided into sections that correspond to the broad categories of questions asked in the stakeholder survey.

Summary of Key Stakeholder Comments	Where Comment is Addressed[1]
Reliability Standards	
Improve articulation of the need for a new Reliability Standard before development.	II(A)(6)(a); II(A)(6)(b); II(A)(6)(d) In 2013, NERC spearheaded an "informal development" effort, which uses informal groups composed of industry subject matter experts to conduct early outreach to industry stakeholders prior to initiating formal development of new or revised Reliability Standards. This early outreach encourages stakeholder conversations to obtain inputs on the proposed Reliability Standards development project. This approach is positively affecting how standard drafting teams are conducting their work. The Reliability Issues Steering Committee (RISC) provides a framework for steering, developing, formalizing, and organizing recommendations to help NERC and the industry effectively focus their resources on the critical means to improve the reliability of the bulk power system (BPS). In some cases, this includes recommending reliability solutions other than the development of new or revised Reliability Standards and offering high-level stakeholder leadership engagement and input on issues that enter the Reliability Standards process. In other cases, the development of a new Reliability Standard or modification of an existing Reliability Standard may be the best way to address a particular issue.
Speed up the process for developing Reliability Standards.	II(A)(6) Projects that were initiated and completed after FERC's approval of the *Standard Processes Manual* (SPM) changes, effective June 26, 2013, have shown significant increases in efficiency while simultaneously improving quality. Implementing the revisions within other projects that were already in process has also resulted in improvements.

[1] Unless otherwise indicated, all references in this table are to the *Overview of NERC Activities and Accomplishments in the Five-Year Period*.

	The most significant improvement is the composite result of all the revisions – the amount of time required to develop a quality Reliability Standard. As reported in the *Analysis of NERC Standards Process Results, Fourth Quarter 2013* filing, the baseline for the time to revise an existing Reliability Standard was approximately 27 months and 40 months to develop a new Reliability Standard. The times to produce each of the eight standards development projects that began formal development after implementing the revised SPM were dramatically reduced. Six and one-half of the projects (GMD Phase 1, INT, Physical Security, MOD A, MOD B, PER, and one of the two standards in the VAR project (VAR-001)) completed formal development from posting the SAR to being adopted by the NERC Board of Trustees in less than seven months. The remaining Reliability Standard in the VAR project (VAR-002) and the MOD C project completed formal development in ten months.
Better articulate how prioritization is determined in the Reliability Standards development process.	II(A)(1)-(4); II(A)(6)(a)-(b) The *Reliability Standards Development Plan 2014-2016* (RSDP) prioritizes future Reliability Standards projects as high, medium, low, or pending technical committee input based on a series of inputs. Prioritization considerations were influenced by: (i) RISC areas of risk and category rankings; (ii) outstanding regulatory directives; (iii) regulatory deadlines; (iv) Paragraph 81 retirement candidates; (v) content and quality assessments by the Standards Independent Experts Review Panel (IERP); and (vi) additional considerations such as fill-in-the-blank status and five-year standards review assessment commitments. The RISC provides input into prioritizing Reliability Standards development activities by providing input to the RSDP in two ways: first, by considering whether the projects identified in the RSDP address areas of risk for the BPS; and second, by developing a priority rank for each of the projects. In reviewing the priority of each project, the RISC provides a mechanism for addressing any scheduling conflicts between projects through the development process. NERC will continue working with the RISC to develop risk profiles for the ERO, which will include high impact low frequency (HILF) issues. These profiles of the BPS will inform how the ERO prioritizes and ranks reliability risks. For high priority risks, NERC will develop project plans and business case assessments outlining initiatives to address those risks.

Provide greater clarity regarding the "Applicability" section of each Reliability Standard.	Where practical, the applicability of Reliability Standards is being targeted to entities meeting specific requirements. This effort narrows applicability to specifically identified entities within registered functions, thus focusing requirements to entities where the actions impact the reliability of the BPS. For example, in PER-005-2, rather than the Reliability Standard being applicable to all Transmission Owners, it is applicable to those Transmission Owners that have: *Personnel, excluding field switching personnel, who can act independently to operate or direct the operation of the Transmission Owner's Bulk Electric System [(BES)] transmission Facilities in Real-time.* Additionally, the Reliability Standard narrows applicably from all Generator Owners to those Generator Owners that have: *Dispatch personnel at a centrally located dispatch center who receive direction from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner, and may develop specific dispatch instructions for plant operators under their control. These personnel do not include plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay dispatch instructions without making any modifications.*
Clarify avenues to obtain information regarding the development history of Reliability Standards. Streamline and enhance communications regarding the development of Reliability Standards to be more useful to industry.	II(A)(7); II(A)(6)(a) The revision of the NERC public website that was implemented during the assessment period significantly increased the information available on this topic and improved the ease of accessing it. On the current website, all Reliability Standards are available to stakeholders on the "Standards" webpage (*see* "Program Areas & Departments"). The "US Enforcement Dates" link on the page offers listings for: (i) Reliability Standards that are currently enforceable in specific jurisdictions (i.e. in the U.S. and Canadian provinces); (ii) Reliability Standards pending regulatory approval; (iii) Reliability Standards approved by the NERC Board of Trustees and pending regulatory filing; and (iv) Reliability Standards no longer subject to enforcement. This page also includes information regarding the enforcement dates for Reliability Standards and, for standards pending enforcement, the NERC Board of Trustees adoption date and the date the standard was filed with FERC. Stakeholders can also locate

	historical information on the "US Enforcement Status/Functional Applicability" link, which offers information regarding when the NERC Board of Trustees adopted, filed or retired requirements. It also provides the date standards were filed with FERC, the effective date of the FERC order and the enforcement date of each requirement. Stakeholders may see all prior versions of standards on the "Reliability Standards" section of the webpage. A click on the "related information" for link for each standard will provide access to historical project development pages. In 2012, NERC launched an improved interface, the VRF matrix, to allow stakeholders to filter the complete set of Reliability Standards so that they could identify which Reliability Standards were applicable to their respective registered functions. Work is ongoing to improve the completeness and timeliness of the above information for non-U.S. jurisdictions (i.e., Canadian provinces or Mexico). Additionally, beginning in 2013, interested entities can track current Reliability Standards development projects in a publicly posted spreadsheet, the *Project Tracking Spreadsheet*, available on the left navigation tab of the NERC Standards home page. NERC updates this spreadsheet monthly. The spreadsheet also provides a link to the projects page, the deliverables, the number of Paragraph 81 requirements, the number of regulatory directives or guidance, the Project Management and Oversight Subcommittee (PMOS) liaison assigned to the project, the NERC Reliability Standards developer, and a month-by-month timeline. Also in 2013, NERC began posting the *Projected Standards Posting Schedule*, which provides the industry with an outlook of near term postings.
Provide greater transparency regarding the process for selecting standard drafting teams and the rationale for standard drafting team decision-making.	II(A)(6)(a) NERC has improved the composition of standard drafting teams by enhancing the selection process to identify, for each project, the necessary technical, writing, and project management expertise to form a balanced team that will foster improved effectiveness and enhanced efficiency. These changes were instituted as a result of the recommendations made by the Standards Process Improvement Group (SPIG) to modify the way NERC develops Reliability Standards, which resulted in revisions to the SPM. In these revisions, NERC memorialized the intent to revise the composition of standard drafting teams to ensure they are appropriately equipped to meet reliability objectives (e.g., by adding legal and compliance experts).

	Additionally, the NERC Standards Committee created a new subcommittee, the PMOS that acts as an industry and standard drafting team partner. The PMOS assigns a representative to each standard drafting team for the purpose of oversight. This oversight includes such actions as: (i) assisting the standard drafting team in understanding any stakeholder concerns; (ii) reaching out to stakeholders if they do not understand the actions being taken by the standard drafting team; (iii) being partners in reviewing the standards for quality; and (iv) assisting with advice on a range of topics from direction to posting schedules. This group has assisted standard drafting teams in avoiding or overcoming hurdles during the process. The revisions made to the SPM and other changes made to the standards development process, including strengthened partnerships, while still in their infancy, are showing great promise as improvements to the process, both in creating efficiency and improving quality. These improvements have allowed the ERO Enterprise to make significant progress towards achieving a body of steady-state Reliability Standards.
Provide a detailed explanation as to how the Standards improve reliability for the industry.	II(D)(1)-(2) This *Five-Year ERO Performance Assessment Report* shows that NERC is improving the performance of, and mitigating risks to, the BPS as measured by avoidable outages. Further, as detailed in NERC's *State of Reliability 2014* report, the number of BPS transmission-related events resulting in loss of firm load, other than events caused by factors external to the transmission system's actual performance (i.e., weather-initiated events), decreased from an average of ten per year over a ten-year period (2002 through 2011) to seven in 2013. The daily severity risk index value, a new metric created by NERC that measures risk impact or "stress" from events resulting in the loss of transmission, generation, and load, has been stable from 2008 to 2013. Including weather-initiated events, 2013 had no high-stress days, which is within the range of zero to seven days experienced during 2008 through 2013. The availability of the bulk transmission system continues to remain high with no statistically significant change from 2008 to 2013. This improved performance is due to a combination of activities led by the ERO Enterprise. NERC Reliability Standards are one component of these activities; they are designed to prevent events that are detrimental to the reliability of the BPS. As detailed in this *Five-Year ERO Performance Assessment Report*, during the

	assessment period, NERC's compliance monitoring and enforcement efforts have matured into a robust program that provides industry with more certainty on actions, outcomes, and reliability consequences. The actions taken to identify, correct, and prevent violations of Reliability Standards have promoted the reliability of the BPS. For example, the adoption and rigorous enforcement of NERC's transmission vegetation management Reliability Standard, which became mandatory and enforceable in 2007, has dramatically reduced the number of outages caused by vegetation growing into high voltage lines. From 2004 through 2008, there were 58 reported outages. By contrast, from 2009 through 2013, only six instances were reported. The RISC identifies new or emerging issues that could impact the reliability of the BPS, and various solutions for mitigating those issues are investigated. Those solutions may include the development of a Reliability Standard, a guideline, necessitate an alert, initiate training, or other potential solutions tailored to the issue. It is the combination and sequencing of these actions – identify risk, determine solutions (of which a standard may be one), monitor compliance or adherence to the solution, and monitor until issue is resolved – that improves the reliability of the BPS. NERC will continue working with the RISC to develop risk profiles for the BPS, which will include HILF issues. These risk profiles of the BPS will inform how the ERO prioritizes and ranks reliability risks. For high priority risks, NERC will develop project plans and business case assessments outlining initiatives to address those risks.
Consider equally or more effective tools than a Reliability Standard for emerging issues such as Geomagnetic Disturbances (GMD), new Critical Infrastructure Protection (CIP) threats such as coordinated physical attack, cold weather preparedness, etc.	NERC will continue working with the RISC to develop risk profiles for the BPS, which will include HILF issues. These profiles of the BPS will inform how the ERO Enterprise prioritizes and ranks reliability risks. For high priority risks, NERC will develop project plans and business case assessments outlining initiatives to address those risks. This will include evaluating whether the risk is most effectively and efficiently addressed through a new or revised Reliability Standard or through some other initiative. In response to direction from the NERC Board of Trustees in February 2013, NERC developed a Reliability Risk Management (RRM) process to create and execute plans for managing reliability risk and to integrate these plans with the business

	planning and budgeting process. The RRM process leverages several resources including the business acumen of the RISC.
Continue to integrate recommendations of the RISC into NERC's decision-making.	II(A)6)(b); II(D)(1) NERC will continue working with the RISC to develop risk profiles for the BPS. These profiles of the BPS will inform how the ERO Enterprise prioritizes and ranks reliability risks. For high priority risks, NERC will develop project plans and business case assessments outlining initiatives to address those risks. In response to direction from the NERC Board of Trustees in February 2013, NERC developed a RRM process to create and execute plans for managing reliability risk and to integrate these plans with the business planning and budgeting process. The RRM process leverages several resources including the business acumen of the RISC.
Consider alternatives such as the forum process, which engages asset owners, to address reliability issues.	II(A)(8)(e); III(D)(3) NERC has used and will continue to use the North American Transmission Forum (NATF) and North American Generator Forum (NAGF), where efficient and appropriate, to address reliability issues. For example, the response to FERC's directive to develop and submit a physical security Reliability Standard within 90 days offered an opportunity for NERC to use the forum process to solicit industry input. On April 1, 2014, NERC staff convened a technical conference to focus stakeholder discussion on developing a draft of CIP-014-1 – Physical Security, with the intent of assisting the standard drafting team to quickly develop and post a Reliability Standard for comment and ballot. The conference provided a forum for industry input on the concepts in the draft Reliability Standard, to include criteria for determining applicable entities, identification of critical facilities, evaluation of potential threats and vulnerabilities, development and implementation of physical security plans, and the proposed standard's implementation plan. NERC Compliance staff also provided an overview of the Reliability Standard Audit Worksheet (RSAW) approach. Additionally, NERC is collaborating with the NATF and the NAGF to further enhance the Event Analysis process and lessons learned dissemination in identifying risks to the BPS.
Compliance Operations	

Provide better oversight to ensure consistency in auditing practices.	II(C)(2)(a); Attachment 3 – (II)(B)[2] During the assessment period, the Regional Entities made meaningful progress in improving their compliance monitoring programs and their audit practices and procedures consistent with the requirements of the NERC Rules of Procedure (specifically, the *Compliance Monitoring and Enforcement Program* (CMEP), Appendix 4C) and the Regional Delegation Agreements. Overall, the Regional Entities worked diligently to plan and complete their scheduled compliance audits during the assessment period. NERC's oversight of the Regional Entity compliance programs shows that the Regional Entities are meeting the baseline requirements of the NERC Rules of Procedure and the Regional Delegation Agreements. However, NERC's oversight has also shown (as this comment suggests) that there continue to be varying compliance monitoring practices across the ERO Enterprise. NERC has three main objectives for the continued evolution of the compliance monitoring program. First, the Regional Entities are revising their existing practices to better align with risk using generally accepted audit practices. Second, NERC and the Regional Entities have developed a standardized *Compliance Auditor Checklist* and *Compliance Auditor Handbook*, as found in the *ERO Enterprise Compliance Auditor Manual*, to ensure consistent conduct of audits across the ERO Enterprise. Third, NERC, in conjunction with the Regional Entities, have developed competency (qualifications) guidelines for compliance monitoring staff and are developing training to accompany the competency guidelines.
Provide greater clarity on the Reliability Assurance Initiative (RAI) to inform industry about what is expected.	II(C)(2) To foster dialogue and seek industry feedback on the various aspects of RAI, NERC hosted a series of workshops in 2013 that addressed important components of RAI including defining internal controls, conducting risk assessment, launching pilot programs, enhancing the Find, Fix, Track and Report (FFT) process, and improving self-reporting. NERC also included the Compliance and Certification Committee (CCC) in the development and review of RAI activities including the development of white papers on internal controls and other guidance.

[2] Attachment 3 to the *Five-Year ERO Performance Assessment Report* is titled *NERC Assessment of Regional Entity Delegated Functions*.

	Compliance-related activities under the RAI program will help achieve a risk-based approach for compliance monitoring by evaluating current compliance monitoring practices, identifying improvements, and addressing the consistent application of audit techniques and the use of uniform tools to carry out compliance monitoring activities. Similar to the RAI compliance monitoring effort, the enforcement element of RAI seeks to align the ERO Enterprise's enforcement processing activities with levels of risk to the reliability of the BPS. Achieving this alignment will promote efficiencies for both the ERO Enterprise and registered entities by eliminating undue regulatory burdens, streamlining documentation and filing requirements, and substantially improving the processing of noncompliance and related mitigating activities.
Improve communications regarding how registered entities are to demonstrate compliance by making them more substantive, timely, and useful to the industry.	II(C)(2); Attachment 3 – II(B)(1)-(2) In 2013, NERC and the Regional Entities began to develop and implement tools that will define techniques and methods to perform compliance monitoring in a consistent manner across the ERO Enterprise. The Regional Entities began using the first of these tools, the *Compliance Auditor Checklist*, in August 2013. In December 2013, NERC and the Regional Entities completed the first draft of a companion document for the *Compliance Auditor Checklist*, the *Compliance Auditor Handbook*, as found in the *ERO Enterprise Compliance Auditor Manual*. NERC disseminated the manual and provided initial training to Regional Entity auditors during the first quarter of 2014. In the second quarter of 2014, the Regional Entities began to use the *ERO Enterprise Compliance Auditor Manual* and its related processes and procedures on a select number of audits. Throughout 2014, NERC and the Regional Entities will revise and expand the manual to address additional audit topics, reflect additional processes developed through RAI activities, and include lessons learned. NERC has made the *Compliance Auditor Checklist* and *Compliance Auditor Handbook*, as found in the *ERO Enterprise Compliance Auditor Manual*, available to industry. A second key RAI compliance activity, the Prototypes and Pilot program, focuses on the development and implementation of a formalized approach to risk assessments and testing of management controls. NERC and the Regional Entities initiated the first phase of the pilot program during 2013. This phase explored different approaches to applying risk-based auditing

	concepts (e.g., audit scoping, reliability risk assessments, and management controls review and testing). For 2014 and beyond, a team consisting of NERC, Regional Entity, and industry representatives as well as an independent audit consultant will evaluate the findings and determine the best audit approach to implement throughout the ERO Enterprise. In addition, NERC and the Regional Entities have consolidated the annual CMEP Implementation Plans into a single document with the goal of implementing certain risk-based compliance enhancements. The CMEP Implementation Plan is provided to stakeholders annually. Finally, NERC has aligned the RSAW development process with the development and publishing of balloted Reliability Standards. This initiative enables stakeholders to follow the development of this compliance monitoring tool contemporaneous with the development of the Reliability Standard to which it relates, and to provide comments on the draft RSAW.
Reassess the role of Compliance Application Notices (CANs) in an audit.	(II)(A)(4) CANs were notices drafted to respond to questions that arose in the compliance monitoring process regarding how to assess compliance. Although developed for the use of audit teams and other compliance monitoring personnel, CANs were posted on the NERC website to provide transparency to industry. However, since CANS were drafted well after the related Reliability Standard was developed, the compliance assessment positions articulated in the CANs often varied from industry's perspective of the intent of the Reliability Standard or requirement at the time of its development and adoption. The CAN process demonstrated that there is a need for concurrent development and dialogue between standard drafting teams and Compliance Operations staff. As a result, in 2013, NERC began incorporating the concurrent development of compliance assessment information into the Reliability Standards development process. After June 2013, informal development project teams began posting documents during standards development titled "Compliance Input." These documents provided questions from industry and answers developed by Compliance Operations staff regarding how to assess compliance for specific requirements, or phrases in the requirements, of the proposed Reliability Standard. This basic

	tool opened the door for discussions between the standard drafting teams and Compliance Operations staff. It also allowed for discussions regarding the wording of requirements and the effect of that wording on how compliance would be assessed. The move to develop RSAWs concurrently with Reliability Standard development eliminates the need for CANs, as separate documents, effective February 2013.
Make RSAWs available before, during, and after the balloting process and ensure that they do not exceed the scope of the Requirement.	(II)(A)(4) As a result of the new processes adopted during the assessment period as described in the preceding response, RSAWs are now written concurrently with new Reliability Standard development projects. A draft RSAW is now posted during the formal comment period and prior to the ballot period for a Reliability Standard, thereby allowing stakeholders to provide comments or to raise concerns about the RSAW at that time.
Ensure that compliance guidance tools like Case Notes, Compliance Analysis Reports (CARs), CANs and Bulletins are used for guidance only, and not as vehicles for interpretations of or revisions to Reliability Standards.	Compliance training going forward will reinforce the fact that documents cannot interpret Reliability Standards. NERC has eliminated CANs (as noted in a previous response), and RSAWs are meant only as guidance to obtaining and reviewing evidence in order to obtain reasonable assurance of compliance with reliability standards. Any existing documents that are used as audit guidance will be addressed to remove language that interprets the Reliability Standard and all training going forward will be developed to demonstrate testing and audit methodology only.
Provide small entities with additional guidance regarding scoping their internal self-assessments and programs.	The purpose of RAI is to assure that entities and auditors focus on relevance. In this connection, as processes are developed for the assessment of risk and more specifically linking risks to functions and Reliability Standards, this will allow a registered entity (including smaller entities) to receive better guidance on where they should focus. Over the course of the next few months, this guidance will be published and supported with training to help smaller entities target their specific risks.
Require self-certifications only for quarters in which a misoperation occurred, rather than for every quarter.	The Regional Entities review self-certifications for all registered entities at least once annually. Regional Entities have the discretion to require monthly self-certifications for certain Reliability Standards and requirements.

Clarify how registered entities will be impacted by improvements to RAI.	II(C)(2) Building upon the success of FFT through RAI, NERC and the Regional Entities are creating additional incentives to discourage poor performance and encourage positive behaviors that contribute to higher accountability and improved reliability performance. In 2013, NERC began implementing RAI processes that promote more effective reliability risk mitigation by encouraging development and enhancement of internal management controls and corrective action programs at registered entities. Achieving the desired alignment of enforcement processing and compliance monitoring with levels of risk will benefit registered entities by eliminating undue regulatory burdens, streamlining documentation and filing requirements and improving the processing of noncompliance and related mitigating activities. The development of tools like the *Compliance Auditor Checklist* and *Compliance Auditor Handbook*, as found in the *ERO Enterprise Compliance Auditor Manual*, also help to set clear expectations for registered entities regarding audit practices and procedures; thereby allowing them to increase the efficiency and effectiveness of their pre-audit preparation. The ability to appropriately evaluate the risks of a registered entity will result in a more appropriately scoped audit and test plan in contrast to a one-size-fits-all approach to compliance. The more the ERO Enterprise understands the control environment and function of controls, the frequency and extent of oversight will change accordingly. In addition to compliance, sound controls also drive organizational efficiencies for the registered entities. Overall, a positive impact of RAI for registered entities is expected to be a more efficient compliance monitoring process that enables registered entities to reduce the extent of time and resources expended on external compliance monitoring activities by implementing or improving effective internal controls to minimize reliability risk.
While some regions are already employing RAI-like approaches in audits and other compliance enforcement activities, all	II(C)(2); Attachment 3 – II(B)(1); II(D)(1)(b)(iv); II(D)(1)(c)-(d) NERC is developing standardized training for Regional Entity compliance auditors to ensure that Regional Entities are consistently (both within each Regional Entity and across all

regions should be implementing an ERO-wide program as soon as possible.	Regional Entities) applying the procedures and methodologies of the new compliance monitoring documents such as the *Compliance Auditor Checklist* and *Compliance Auditor Handbook*, as found in the *ERO Enterprise Compliance Auditor Manual*, and RSAWs.
Enforcement	
Treat similar findings with greater consistency.	II(C)(4)(b); Attachment 3 – II(D)(1)(d) NERC and the Regional Entities engage in a number of activities to enhance consistency in enforcement processing across the ERO Enterprise. NERC and the Regional Entities participate in a multi-region working group on enforcement activities. Through this group, NERC communicates guidance and provides training on many different aspects of the enforcement program. This group is actively involved in the development or enhancement of any enforcement activities. In addition, NERC conducts oversight to ensure the consistent application of enforcement processing mechanisms and other enforcement-related processes under the CMEP. Examples of NERC's oversight includes the annual review of FFTs which results in a public report filed with FERC. Additionally, NERC reviews and approves all Notices of Penalty (NOPs) prepared and submitted by Regional Entities. One aspect of NERC's review of NOPs is to ensure that similar actions and inactions are treated consistently within and across Regional Entities in terms of whether a violation is determined to have occurred; and, to ensure that consistent penalty determinations are made for similar violations, both within the Regional Entity and across the Regional Entities.
Streamline and refine the scope of investigations.	Attachment 3 – II(C); IV(A) The NERC Rules of Procedure permit all eight Regional Entities and NERC to conduct compliance investigations (CIs), and it is extremely important for the ERO Enterprise to have a consistent approach for this activity. NERC developed a CI leaders training class to provide a methodology for the conduct of the CI process. The class introduces the approach of conducting CIs in phases, with accompanying activities and deliverables for each phase. It also explains the roles of the Regional Entity, NERC, and the applicable governmental authority in CIs. One of the key messages in the class is to reinforce that CIs are one of several formal compliance monitoring tools, and there are

	specific circumstances where a CI may be the best tool, and other circumstances where a CI is not the best tool. In addition, the class introduces the Events Analysis process. NERC found that Compliance staffs benefit from additional exposure to and familiarity with this process. The Event Analysis process has greatly reduced the number of CIs, as the Event Analysis process provides the relevant facts and circumstances of events that were previously only available through the tools employed in a CI.
While efforts are outlined in the report regarding a transition to a risk-based approach for compliance and enforcement, including discretion, targeted measurable improvements are still needed.	II(C)(4)(a); Attachment 3 – II(B)(1); II(D)(1)(b) NERC and the Regional Entities have continued to work collaboratively to develop and implement a set of metrics to measure the efficiency with which enforcement items are processed. The four metrics which have been developed during the assessment period to monitor the performance of NERC and the Regional Entities in processing enforcement items are: (1) Caseload Index – computes the number of months it would take to clear the violations in a Compliance Enforcement Authority's (CEA, i.e., NERC or a Regional Entity) inventory based on the CEA's average monthly processing rate for the preceding twelve-month period; (2) Violations in Inventory – reports the number of violations in the CEA's caseload; (3) Violation Aging – reports, by Regional Entity, the number of violations discovered in each year beginning with 2007 which have not been filed with the Commission or otherwise resolved; and (4) Mitigation Activity Aging – identifies the status of mitigation activity based upon age of violations. These metrics now provide quantitative measures by which efficiency gains (or losses) in enforcement processing can be seen and resources can be focused on areas as needed to improve performance.
Increase the timeliness of enforcement processing.	II(C)(4)(a); Attachment 3 – II(D)(1)(b)(i)-(ii) The ERO Enterprise has achieved significant success in processing older cases and reducing processing times. NERC

	tracks enforcement processing rates through its Caseload Index metric. The ERO Enterprise has demonstrated substantial improvement in this metric from July 2011 through the end of 2013. By working to reduce the number of aging violations while improving the processing speed for newer violations, NERC and the Regional Entities reduced the average age of violations in the ERO caseload by six percent in 2013, from 11.86 months in 2012 to 11.2 months. Other data on improvements in the timeliness of enforcement processing is provided in III(D) of Attachment 3. As noted in that section, as of December 31, 2013, several Regional Entities had completed processing of all or virtually all of their enforcement items that were discovered before 2012, thereby achieving or moving toward achievement of the ERO Enterprise goal of completing processing of all enforcement items within 24 months after discovery.
Provide greater transparency and detail regarding penalty calculation and enforcement in general.	II(C)(4)(b); Attachment 3 – II(D)(1)(d) NERC and the Regional Entities have taken steps to increase the transparency regarding penalty calculations and enforcement in general. With respect to penalty calculations, each of the Regional Entities considers the factors set forth in the NERC *Sanction Guidelines* when assessing penalties. During the assessment period, the *Sanction Guidelines* were significantly revised to simplify them and state more clearly how mitigating and aggravating factors are to be taken into account in penalty determinations. NERC conducts ongoing oversight of the penalty determination process, reviewing each penalty determined by a Regional Entity to ensure consistency with other penalties assessed across the ERO Enterprise for similar violations occurring under similar facts and circumstances. NERC also reviews Regional Entity processes associated with all aspects of the enforcement program. NERC also provides information on enforcement actions, trends, and metrics on a regular basis, usually by posting the information on its website. In 2013, NERC conducted a training session to better enable stakeholders to locate all publicly available enforcement-related information.
Treat repeat violations that could not have been prevented by any of the mitigating activities approved by the Regional	II(C)(2)(b); Attachment 3 – II(D)(1)(c)(ii) The ERO Enterprise works closely with registered entities to develop mitigating activities that will both address the noncompliance as well as work to prevent future reoccurrence. These are by definition fact-specific determinations.

Entity and NERC similarly as non-repeat violations.	Violations are considered repeat when the conduct underlying the two violations is repetitive. As a general matter, whether a repeat instance of noncompliance will be treated as a repeat violation for the purposes of compliance history, and whether that compliance history will warrant aggravation of the monetary penalty under the *Sanction Guidelines* in a given case, necessarily depends on the facts and circumstances of the specific case.
Provide sufficient details regarding the different tracks for disposition of compliance issues, and explain how the CEA will make the determination as to which is the proper track for disposition. Also, explain how the oversight roles will be administered between the CEA Compliance staff, the CEA Enforcement staff, NERC, and FERC.	II(C)(2)(b); II(C)(4)(b); Attachment 3 – II(D)(1)(d) The different tracks for disposition of compliance issues are as follows: (1) The FFT program, which was recently enhanced to include additional possible violations; (2) The Spreadsheet Notice of Penalty (SNOP) format; and (3) The full NOP format. The criteria for use of each disposition are discussed in Attachment 3. In addition, the ERO Enterprise, through the RAI, is developing mechanisms for addressing noncompliance outside of the enforcement process through the use of greater enforcement discretion. Under this initiative, minimal risk issues will be eligible to be recorded as compliance exceptions and mitigated without triggering an enforcement action. Among other things, NERC reviews and approves all violations filed through the SNOP or full NOP mechanisms. NERC also conducts a monthly sampling and yearly spot check of issues posted by each Regional Entity through the FFT program to ensure that the issues processed through FFT are appropriate for the FFT program, and to identify areas for further improvement. NERC and FERC maintain visibility and exercise oversight over all noncompliances, regardless of the disposition track (FFT, SNOP, full NOP, or compliance exception). FERC reviews each filing or posting and also conducts a yearly review of a sample of issues posted as FFTs.
Associate timeframes with CEA actions to be taken during the disposition process. This will provide a tracking measure to help expedite processing of low reliability risk violations.	II(C)(4)(a); Attachment 3 – II(D)(1)(b)(i), (ii), (iii) NERC works closely with each of the Regional Entities to ensure that noncompliance is processed in a timely and efficient manner and measures performance through a number of metrics. These metrics include the Caseload Index, Violations in Inventory, Violation Aging, and Mitigation Activity Aging. These metrics

	are described in further detail in II(C)(4)(a) of the *Overview of NERC Activities and Accomplishments in the Five-Year Period* and in II(D)(1)(b) and the individual evaluations of the Regional Entities in Enforcement in Attachment 3. The time needed to process a particular case may vary considerably based on the facts and circumstances of that case. However, NERC has developed and is using the above-referenced metrics to monitor overall increases and decreases in the timeliness and efficiency of enforcement processing activities by each Regional Entity.
Better communicate and emphasize the benefits of self-reporting.	II(C)(1); II(C)(2)(b); Attachment 3 – II(D)(1)(c)(i) To encourage registered entities to take proactive steps to self-identify their noncompliance and thereby promote a more reliable BPS, the ERO Enterprise provides certain incentives. For example, self-reporting is considered a mitigating factor in the penalty determination pursuant to the *Sanction Guidelines*. In addition, whether or not noncompliance was self-reported is a factor considered when selecting a streamlined disposition track such as FFT. Further, as the RAI is implemented, the extent of a registered entity's self-reporting of noncompliances (versus discovery by the CEA) will be a factor considered in evaluating the quality of the registered entity's internal controls and therefore the frequency, nature and extent of compliance monitoring of the registered entity. Early self-identification, self-reporting, and mitigation of noncompliance are important steps in improving electric reliability. NERC has established a corporate goal that reflects the importance of self-reporting and closely tracks progress with respect to this goal.
Do not issue penalties for administrative violations.	NERC does not believe that it is appropriate to determine whether or not to assess a penalty based solely on whether the violation is characterized as "administrative." The disposition of any instance of noncompliance, including whether a penalty is appropriate, is based on the risk posed by the noncompliance to the reliability of the BPS as well as other factors. Penalties were assessed for 52% of the violations processed in 2012 and 2013.
While NERC has made progress toward reducing its caseload through FFT and the bulk processing of	II(C)(1); II(C)(2)(b); Attachment 3 – II(D)(b) NERC and the Regional Entities are continually exploring ways to adopt streamlined processes to resolve noncompliances or to

violations, effort should be made to reduce time spent by the registered entities.	improve the efficiency of existing processes. During the assessment period, NERC adopted and enhanced several streamlined enforcement processing tracks. Through the metrics that have been developed, as described in earlier responses, NERC is able to monitor increases and decreases in enforcement processing timeliness and efficiency at each Regional Entity. The metrics are showing that progress is being made, e.g., as evidenced by reduction of processing times and reduced caseloads In addition, the ERO Enterprise has enhanced outreach efforts so that time spent by registered entities in providing information regarding noncompliance, risk, and mitigation is more efficiently and effectively used. For example, NERC and the Regional Entities recently distributed the *ERO Self-Report User Guide* and *ERO Enterprise Mitigation Plan Guide*. These documents were developed by NERC and the Regional Entities to provide guidance to registered entities on submitting self-reports and mitigation plans that have all of the details necessary to facilitate timely processing and avoid protracted follow-up periods and requests.
Clarify how registered entities will be impacted by improvements to the FFT program.	II(C)(1); II(C)(2)(b); Attachment 3 – II(D)(b)(iv) Through the use of FFT, the ERO more efficiently resolves instances of noncompliance that pose a lesser risk to BPS reliability, recognizing that efficient disposition of such issues allows the ERO Enterprise and industry to devote its emphasis and resources to more important reliability matters. The FFT process provides incentives for self-reporting and encourages registered entities to continue to aggressively self-identify, self-report, and mitigate reliability issues. Recent expansion of the scope of the program to possible violations posing a moderate risk to reliability, as well as issues that will be mitigated after the FFT posting, make this efficient enforcement processing mechanism available for a larger number of possible violations. Issues resolved through the FFT process are typically resolved more expeditiously than issues resolved through other disposition tracks. Further, resolution through the FFT track means that those issues will not result in the assessment of a monetary penalty.
Describe the efficiency and effectiveness of the compliance and	II(C)(2), (4); Attachment 3 – II(D)(1)

enforcement programs and their impact on reliability in light of the high percentage of lower risk violations.	The actions taken by the ERO Enterprise to identify, correct, and prevent violations of NERC's Reliability Standards have promoted the reliability of the BPS. For example, the adoption, modification, and rigorous enforcement of NERC's transmission vegetation management Reliability Standard (FAC-003), which became mandatory and enforceable in 2007, has dramatically reduced the number of outages caused by vegetation growing into high voltage lines. Beyond individual standards, the ERO Enterprise compliance and enforcement programs promote reliability by encouraging registered entities to create and maintain cultures of compliance. The ERO Enterprise creates incentives for registered entities to proactively self-identify and mitigate noncompliance. For example, the FFT program allows for a streamlined disposition of noncompliances without a monetary penalty being assessed. Through the RAI, NERC and the Regional Entities are working together to implement further enhancements that will allow minimal risk noncompliance to be processed outside the enforcement track. NERC and the Regional Entities are also developing and implementing procedures and processes to enhance auditing approaches across the ERO Enterprise. These efforts will allow registered entities and the ERO Enterprise to shift toward a risk-based model of compliance and enforcement, thereby allowing registered entities to dedicate more of their resources toward addressing issues posing greater risks to reliability.
Clarify how NERC's compliance monitoring and enforcement efforts have matured into a "robust program that provides industry with more certainty on actions, outcomes, and reliability consequences."	II(C); Attachment 3 -II(D)(1)(a) During the assessment period, NERC and the Regional Entities worked on increasing consistency in compliance monitoring processes across the ERO Enterprise. These efforts have included the development of common auditor qualifications and competency requirements, development of the common *Compliance Auditor Checklist* and *Compliance Auditor Handbook*, as found in the *ERO Enterprise Compliance Auditor Manual*, and development of a common training program for auditors. During the assessment period, NERC and the Regional Entities also worked to develop more mature enforcement processes for the ERO Enterprise. The resulting efficiency gains in enforcement processing ensure that final outcomes relating to noncompliances are known earlier.

	The implementation of streamlined enforcement processing mechanisms, such as SNOP and FFT, has facilitated the faster resolution of noncompliance items. NERC provides significant transparency regarding the processing tracks that are available and the associated criteria for a noncompliance item to be placed onto each track. In addition, NERC and the Regional Entities worked together to design and build a system for the collection, management, and exchange of compliance-related information between NERC and the Regional Entities. NERC's centralized system and the complementary systems in place at the Regional Entities enable enforcement processing efficiencies and facilitate consistent tracking of violation status across the ERO Enterprise. Further, for several years, NERC has closely tracked various measures regarding the overall performance of the ERO Enterprise as it relates to enforcement activities. Beginning in 2013, NERC and the Regional Entities developed and implemented a series of metrics (described in earlier responses) to track and evaluate the performance of the ERO Enterprise and of each Regional Entity in enforcement processing. These metrics allow NERC to analyze trends and identify areas where further improvements may be achieved.
Registration and Certification	
Enhance the System Operator Certification program by making training for exam preparation more available.	The System Operator Certification program has multiple vendors and individual utilities that have developed NERC system operator certification exam preparation courses. NERC does not believe that further assistance from NERC is appropriate. As an independent certifying entity, if NERC were to develop and/or sponsor training, NERC would compete with established vendors.
Provide greater clarity, guidance, and consistency regarding Coordinated Functional Registration (CFR) and Joint Registration Organizations (JROs), and examine how the process can be streamlined.	II(B); Attachment 3 – II(A) During the assessment period, revisions to NERC Rules of Procedure Section 507 and the addition of Section 508, approved by the Commission on June 10, 2010, clarified the operations of CFR and JRO registrations. Specifically, revised Section 507 allows an entity to register as a JRO on behalf of one or more of its members or related entities for one or more functions for which such members or related entities would otherwise be required to register. The registering entity thereby accepts on behalf of such members or related entities all compliance

	responsibility for that function or those functions including all reporting requirements. Section 508 allows multiple entities to register using a CFR for one or more Reliability Standard(s) or for one or more requirements or sub-requirements with particular Reliability Standard(s) applicable to a specific function. The CFR is the complete registration for each entity, with each entity taking full compliance responsibility for those Reliability Standards or requirements or sub-requirements applicable to the CFR.
Registration should be more carefully tailored and based on sounder reasoning. Update the functional model to provide greater clarity and guidance to registered entities. The risk-based registration concept must be carefully developed and implemented to ensure that entities that remain registered are not adversely impacted.	II(B)(1)-(2); Attachment 3 – II(A) In January 2014, NERC launched the Risk-based Registration Assessment initiative to enhance the compliance registration and certification program to be more efficient and better aligned with reliability benefit. Through this initiative, NERC will register entities and assign appropriate Reliability Standard requirements commensurate with the need to mitigate the risk that they pose to the BES, by scaling registration criteria based on their contributions to reliability. NERC will also develop tools that will enhance a registered entity's understanding of the relevant Reliability Standards and requirements that apply to them. Scoping compliance responsibilities according to BPS reliability risks will equate to better use of resources at both the registered entity level in the implementation of compliance programs, and at the Regional Entity level in their overall compliance monitoring efforts. During the assessment period, NERC revised the definition of the BES in the *Glossary of Terms Used in NERC Reliability Standards*, in response to Commission directives in Order Nos. 743 and 743-A. The objective of the revisions is to ensure consistent inclusion or exclusion of entities and elements that are subject to Reliability Standard requirements. The Commission-approved revised BES definition enables NERC and the Regional Entities to identify assets that are material to the reliability of the interconnected transmission network. By using a set of continent-wide, "bright line" criteria that eliminates regional discretion, the revised definition effectively ensures that the users, owners and operators of BES assets are identified and registered on a consistent basis in order to comply with applicable Reliability Standards. The revised BES definition provides improved clarity for industry by identifying specific categories of facilities and configurations as inclusions and exclusions to the BES. Additionally, the case-by-case exception process to add elements to, and to remove elements from, the BES provides

	transparency and uniformity to the determinations of what constitutes the BES. In summary, the revised, much more detailed and granular BES definition along with the BES exception process should result in greater consistency, transparency and predictability in registration determinations.
Provide additional clarification, guidance, and training regarding the definition of the term BES to ensure consistent application in both Reliability Standards and the compliance registration process.	II(B)(2) In March 2014, FERC approved the revised definition of BES. As described in the preceding response, the revised BES definition provides improved clarity for industry by identifying specific categories of facilities and configurations as inclusions and exclusions to the BES. During the first half of 2014, NERC held communications and training sessions for Regional Entities, registered entities, and NERC staff to address, among other things: (i) evidentiary requirements for BES determinations; (ii) review and appeal mechanisms; and (iii) Reliability Standards applicability. These sessions included workshops and webinars. NERC has a dedicated webpage for information related to the BES definition and the notification and exception processes. This page hosts links to materials that support the application of the BES definition and provide entities with the information needed to make uniform determinations of BES elements. These materials include, among other things, webinars, training videos, process documents, and guidelines. The page is updated as new materials become available. The webpage is available at: http://www.nerc.com/pa/RAPA/Pages/BES.aspx.
Provide an explanation regarding the use of the term BES in certain instances and BPS in other instances.	The full definitions of BES and BPS are contained in the *Glossary of Terms Used in NERC Reliability Standards*. "BPS" is the statutory term in Section 215 of the FPA and sets the outer limit of NERC (and FERC) authority. FERC has accepted NERC's use of the term "BES" and its definition and has indicated that the "BES" does not exceed the scope of the "BPS." Entities that use, own, or operate elements of the BES as established by the FERC-approved definition of BES are: (i) owners, operators, and users of the BPS; and (ii) candidates for registration. Since 2006, NERC has registered entities for one or more functional categories depending on whether it is a user, owner or operator of the BPS.

	NERC has used "BES" principally for registration purposes. In March 2014, FERC approved the revised definition of "BES." As described in a previous response, the revised BES definition includes bright line core criteria with various enumerated inclusions and exclusions. Now that "BES" is clearly defined, the term can be used to determine on a consistent basis the entities that warrant registration and address material impacts on reliability.
Reliability Assessment & Performance Analysis Metrics	
Develop performance measures to determine if a Reliability Standard is actually reducing risk to reliability.	Performance measures from the CMEP assist NERC in assessing whether a Reliability Standard is actually providing more certainty on actions, outcomes, and reliability consequences NERC compliance staff supply standard drafting teams with compliance and enforcement information, statistics, and perspectives to help develop Reliability Standards that provide an increased reliability benefit and clarify compliance risks.
Explain more thoroughly how the information provided in reliability assessments affects the future adequacy and reliability of the BPS.	II(D)(1), II(D)(2), II(D)(3) In response to direction from the NERC Board of Trustees in February 2013, NERC has developed a RRM process to create and execute plans for managing reliability risk and to integrate these plans with the business planning and budgeting process. The RRM process includes the identification of the *ERO Top Priority Reliability Risks* for each upcoming business planning and budget cycle. The development of the list of top ten high priority reliability risks is intended to focus the efforts of the ERO Enterprise program areas, including training and education, Reliability Standards setting, and compliance. NERC developed a set of the top ten priority reliability risks to be focused on in the development of the *ERO Enterprise Strategic Plan 2014-2017*. NERC has also developed a voluntary Event Analysis process that delivers quality, timely and actionable lessons learned to registered entities. NERC assesses every event submitted through the voluntary Event Analysis process to identify and share possible risks to reliability with industry members.
Provide metrics that focus not only on enforcement but also measure performance risk and	VII NERC and the Regional Entities have collaboratively made significant progress in developing a shared, rolling three-year *ERO Enterprise Strategic Plan*, which includes performance

specify specifically what is working and what is not.	metrics. The NERC Board of Trustees approved the 2014 *ERO Enterprise Performance Metrics*. These performance metrics will be used to assess the overall effectiveness of the ERO Enterprise in addressing risk to the BPS, achieving reliability results, measuring and assuring the effectiveness of Reliability Standards and compliance programs, and improving risk mitigation and program execution. NERC's performance metrics include four overarching metrics focused on overall effectiveness in addressing BPS risks and improving reliability. NERC's performance metrics also include a number of supporting measures that assess the effectiveness of the key operational elements of the ERO Enterprise.
Describe the basis for including the 345-kV breaker failures as a potential trend in risk prioritization.	II(D)(2) Circuit breaker failures, in conjunction with another fault, may lead to more BES facilities removed from service than required to clear the original fault. NERC has identified a potential trend of 345 kV SF6 puffer type breakers failing as being one of the ten high priority reliability risks.
Provide a more complete explanation of how the daily severity risk index is used to help prioritize risks.	I(A) The daily severity risk index value, a metric created by NERC that measures risk impact or "stress" from events resulting in the loss of transmission, generation, and load, provides an industry reference for historical BPS reliability. This metric also offers analytical insights toward industry action and enables the identification and prioritization of specific steps that can be implemented in order to reduce and manage risks to reliability.
Training, Education, and Personnel Certification	
Increase the availability and accessibility of training regarding audit preparation, Reliability Standard compliance, Event Analysis, and major NERC initiatives such as BES definition, and CIP Version 5 Reliability Standards.	II(A)(4), II(B)(2), II(C)(2), II(D)(1), II(D)(2), II(D)(3), II(E)(1)(c); Attachment 2, pp. 44, 45;[3] Attachment 3 – II(B)(1)(d) (*NERC Training Activities for Regional Entity Compliance Staff)*; II(B)(2)(a) (*Regional Entity Training, Education and Outreach Programs for Registered Entity Personnel*); II(B)(2)(b)(ii)-(ix) (*Assessments of the Individual Regional Entities*) Between 2011-2013, the Regional Entities' workshops and equivalent training programs attracted more than 30,000 attendees. NERC and the Regional Entities develop new training

[3] Attachment 2 to the *Five-Year ERO Performance Assessment Report* is titled *Joint Regional Entity Self-Assessment*.

	offerings as new needs arise. Recent examples are provided below. Additionally, NERC developed a set of the top ten priority reliability risks to be focused on in the development of the *ERO Enterprise Strategic Plan 2014-2017*. The development of these top ten high priority reliability risks is intended to focus the efforts of the ERO Enterprise program areas, including training and education, Reliability Standards setting, and compliance. NERC is working to provide training to industry (as well as to compliance auditors) on how to assess compliance with new or revised Reliability Standard. This training is provided following FERC approval of a Reliability Standard, but well before the Reliability Standard effective date. To implement the revised BES definition, NERC developed a web-based, ERO Enterprise-wide application to provide a consistent platform for registered entities to submit self-determined notifications and to submit exception requests for inclusions in or exclusions from the BES. This application is called the BESnet Enterprise Application Tool. During the first two quarters of 2014, NERC held communications and training sessions for Regional Entities, registered entities, and NERC staff to address, among other things: (i) evidentiary requirements for BES determinations; (ii) review and appeal mechanisms; and (iii) Reliability Standards applicability. These sessions included workshops and webinars. NERC hosted a series of workshops in 2013 that addressed defining internal controls, conducting risk assessment, launching pilot programs, enhancing the FFT process, and improving self-reporting. In 2013, NERC and the Regional Entities began to develop and implement tools that will define techniques and methods to perform compliance monitoring in a consistent manner across the ERO Enterprise. The Regional Entities began using the first of these tools, the *Compliance Auditor Checklist*, in August 2013. In December 2013, NERC and the Regional Entities completed the first draft of a companion document for the *Compliance Auditor Checklist*, the *Compliance Auditor Handbook*, as found in the *ERO Enterprise Compliance Auditor Manual*. NERC disseminated the manual and provided initial training to Regional Entity auditors during the first quarter of 2014. NERC has made the *Compliance Auditor Checklist* and *Compliance Auditor Handbook*, as found in the *ERO Enterprise Compliance Auditor*

	Manual, available to industry to provide guidance on audit preparation. Specific documentation or other aids to assist in the implementation of the RRM process, document templates, and detailed instructions and training are being developed to support the execution of this process and will be made available to industry. NERC provides registered entities (as well as Regional Entity staff) with cause analysis training. As of December 2013, 164 personnel from all eight Regional Entities and over 600 people from 115 different registered entities have received more than 4,000 hours of cause analysis training, with 432 hours of continuing education hours awarded to 54 NERC-certified system operators. NERC is adding a training and education component to the Event Analysis process to increase the relevance and impact of lessons learned for the Regional Entities, industry, and other stakeholders. Beginning during the assessment period, NERC holds an annual Grid Security Conference (GridSecCon). Over 300 industry and government stakeholders attended the most recent GridSecCon in October 2013. Additionally, almost 200 stakeholders attended credentialed training sessions in cybersecurity and physical security. NERC is committed to working with industry to ensure smooth transition to the CIP Version 5 Reliability Standards. NERC has been collaborating with Regional Entities and responsible entities by establishing a transition program to support implementation of Version 5. NERC has implemented several program elements related to outreach, communication, and training, to include periodic guidance documents to keep industry informed during the transition period. NERC conducted a pilot Version 5 implementation study, which included six volunteer entities that implemented the Version 5 Reliability Standards on an accelerated basis. Future training will include auditor training, technical workshops, guidance, and other lessons learned from the Version 5 implementation study.
Incorporate registered entity independent subject matter experts into the audit process.	Attachment 3 – II(B)(2)(b)(ii)-(ix) (*Assessments of the Individual Regional Entities - Department Structure / Staffing / Conflict of Interest Avoidance*)

	As a key RAI compliance activity, the Prototypes and Pilot program focuses on the development and implementation of a formalized approach to risk assessments and testing of management controls. NERC and the Regional Entities initiated the first phase of the pilot program during 2013. This phase explored different approaches to applying risk-based auditing concepts (e.g., audit scoping, reliability risk assessments, and management controls review and testing). For 2014 and beyond, a team consisting of NERC, Regional Entity, and industry representatives as well as an independent audit consultant will evaluate the findings and determine the best audit approach to implement throughout the ERO Enterprise.
Event Analysis	
Separate Event Analysis from Compliance Operations.	II(D)(3) Event Analysis and Compliance Operations are separate processes. NERC has developed a voluntary Event Analysis process. Participation in this voluntary process does not relieve registered entities of their obligation to comply with NERC Reliability Standards. Registered entities are encouraged to continue performing critical self-assessments of compliance with Reliability Standards in connection with a qualifying event, occurrence or any other time when adherence to the NERC Reliability Standards is in question.
Increase the efficiency and clarity of the compliance assessment process associated with an event.	II(D)(3); Attachment 3 – IV(A) and (C) The annual NERC CMEP Implementation Plan and the *ERO Event Analysis Process* document describe the expected actions by affected registered entities following an event or disturbance. While voluntary on the part of registered entities, this process includes a systematic review of the event against approved Reliability Standards, improved self-reporting and expedited mitigation of any possible noncompliances, thus improving reliability. The Regional Entities use outreach forums and other mechanisms to describe the process and encourage these actions by registered entities.
Streamline the cause coding mechanism.	II(D)(3) NERC is continuously striving to improve how it defines, catalogs and trends the causes of system events. The cause code assignment allows for greater historical trending and predictive analysis. NERC plans to further facilitate event analysis by merging its event-driven databases across the ERO Enterprise

	and defining the relationships between various system cause codes.
Increase the timeliness, transparency and comprehensiveness of dissemination of information relating to Event Analysis and lessons learned.	II(D)(3) NERC is collaborating with the NATF and the NAGF to further enhance the Event Analysis process and lessons learned dissemination in identifying risks to the BPS. NERC plans to improve the timeliness of the availability of and access to final event reports by creating a secure portal that will be accessible by industry to obtain these reports.
Improve the consistency of the NERC alert system by ensuring that alert levels are commensurate with the risk of the issue presented and do not impose unnecessary burdens on registered entities.	II(D)(3) NERC generates alerts in limited circumstances. If an event merits an alert, NERC first discusses the potential alert with Regional Entities and registered entities before disseminating the alert. Under Section 810 of the NERC Rules of Procedure, NERC can issue "Level 1 Advisories," "Level 2 Recommendations," and "Level 3 Essential Actions," depending on the underlying circumstances. Each of these issuances requires different actions (if any) by registered entities. NERC strives to use the issuance that is appropriate to the circumstances so as not to impose undue burdens on registered entities.
Ensure that sabotage events are communicated by NERC Alert.	Not all sabotage events are appropriate for issuing an alert; however, additional information on security-related events is available to all users on the improved Electricity Sector Information Sharing and Analysis Center (ES-ISAC) portal and through other ES-ISAC channels.
Make improvements in full publication of events (under appropriate confidentiality controls) to users, owners and operators.	NERC now has a secure site that allows registered entities to gain NERC-authorized access to reports from other registered entities that have agreed to share such information.
Consider that not all issues identified by the Event Analysis program are issues that should become standards or even alerts.	Reliability issues presenting a risk to the BPS that have been identified by Event Analysis are subject to further NERC consideration and discussion with Regional Entities and registered entities before becoming the subject of a Reliability Standard development project. The decision to issue an alert or develop a Reliability Standard is based on this collaborative process. Additionally, the RISC considers risk-related issues and

	advises the NERC Board of Trustees on the appropriate action to take to address risks to the BPS. *See also* II(A)(6)(a) and II(A)(6)(b)
Critical Infrastructure Protection	
Increase the focus on physical security, in addition to cybersecurity.	II(A)(8)(e); II(E) NERC recognizes that identifying, assessing, and preventing threats and risks to both the physical security and the cybersecurity of the BPS, while always matters of concern, have attained increasing significance in the last three to four years. NERC, through its Critical Infrastructure department, ES-ISAC, and the Critical Infrastructure Protection Committee, is engaged in various activities to address physical security issues. In addition, NERC recently developed and submitted for Commission approval a new physical security Reliability Standard (CIP-014-1).
Increase the speed at which registered entities will be able to learn how CIP Reliability Standards will be interpreted by auditors, and ensure that these interpretations are consistent across the Regional Entities.	II(A)(4) RSAWs are now being written concurrently with new Reliability Standard development projects. Draft RSAWs are to be posted during the formal comment period and prior to the ballot period for the associated Reliability Standards. Stakeholders are encouraged to provide feedback on the draft RSAWs.
Provide additional guidance with alerts that will help avoid public disclosure request responses with CIP-related information.	NERC exercises the utmost caution and will not issue alerts that include sensitive CIP-related information. It is also the responsibility of the entity responding to a request for information to ensure that any sensitive information it provides is appropriately marked and that appropriate exemptions from disclosure are claimed.
Explore a full functional separation of NERC and the ES-ISAC as recommended in the February 2014 report from the co-chairs of the Bipartisan Policy Center's Electric Grid Cybersecurity Initiative.	II(E)(2) NERC is committed to keeping the ES-ISAC separate from NERC's compliance monitoring and enforcement activities and enforcing the Board of Trustees-approved corporate policies that are in place. In addition, NERC is considering a physical separation of ES-ISAC personnel in the Washington, D.C. office.
Strengthen inter-sector coordination: the ES-ISAC should explore ways to	ES-ISAC has acted to strengthen inter sector coordination through increased information sharing and support to ESCC in the following ways:

provide information and support the activities of the Electricity Sub-Sector Coordinating Council (ESCC).	(1) Extensive subject matter expert contribution to "Energizer" and ESCC Playbook products; (2) Alignment of ES-ISAC capability under ESCC to provide operationally informed context and implementation; (3) Full ESCC Senior Executive Working Group participation; (4) National Cybersecurity and Communications Integration Center watch floor and Department of Homeland Security Unified Coordination Group (UCG) participation; and (5) Full participation at Department of Energy Sector Specific Agent (SSA) hosted Clear Path II restoration event and all pertinent OSD Defense Critical Infrastructure Program (DCIP) events. In addition, ES-ISAC contributed subject matter expert leadership to initiation of a pilot continuous monitoring and automated information exchange capability undertaken with selected major utilities, known as the Cybersecurity Risk Information Sharing Program (CRISP). This capability provides foundational support to top future ESCC inter-sector information sharing objectives. Further involvement in CRISP by the ES-ISAC on a permanent basis is under active consideration. Further, ES-ISAC accelerated its own capability maturation consistent with NERC CIPC Information Sharing Task Force and Government-Industry Information Sharing Survey findings with an advanced portal fitted to entity, ESCC Secretariat, and National Council of ISACs cross sector sharing requirements.
Stakeholder Communications, Public Relations, and IT	
Offer more unified, coordinated, and user-friendly IT tools and programs to registered entities.	ERO senior leadership intends to develop ERO Enterprise IT applications, where appropriate, to support common processes, to enhance the efficiency and effectiveness of Regional Entities' practices, to increase the consistency of the interface with registered entities, and to facilitate NERC's oversight function.
Provide greater consistency between NERC and Regional Entity websites.	VII; Attachment 6, pp. 14-16.[4] NERC and the Regional Entities are engaged in several activities to develop unified or consistent IT programs and tools and to

[4] Attachment 6 to the *Five-Year ERO Performance Assessment Report* is titled *NERC's Plan and Initiatives for Improving Coordinated Operations Across the ERO Enterprise*.

	coordinate key messages and direction and enhance consistency across the ERO Enterprise.
Improve technical support, accessibility, and organization of the NERC website.	In 2013, the NERC public website was converted from a legacy platform to a SharePoint site greatly improving search functions, security and scalability of the website. Converting the website to a contemporary off-the-shelf application will allow continued improvements to document organization, and enhanced search capability through the use of metadata. Technical support has been enhanced by usage of the contact form, with relevant questions and comments being directed to the correct program area or to the IT department for resolution.
Reduce travel expenses for registered entities by more frequently changing locations where meetings are held (beyond Atlanta), and increasing the availability of webinars and teleconferences.	Industry engagement is a critical component of NERC's activities and strategic initiatives. NERC uses webinars to engage and educate industry on a number of topics. For example, in 2013 alone, NERC hosted 43 Reliability Standard industry webinars attended by an average of 360 participants. However, NERC decided to move its headquarters from Princeton, N.J. to Atlanta, G.A., among other reasons, because Atlanta is a major airline hub that is directly accessible from many parts of the country. In addition, in selecting meeting locations, NERC must balance the cost to and convenience for potential participants of using Atlanta versus locations other than Atlanta, with the cost savings associated with holding the meeting in NERC's own facilities (rather than in rented space in another location and the travel expenses for NERC staff to other locations.
Improve retention of NERC staff to ensure better, less disruptive functioning of the ERO.	NERC management and the Board of Trustees recognize the importance of retaining experienced employees. Several initiatives are in place or underway to enhance employee engagement, including improving hiring practices, conducting regular check-ins with new staff periodically after hiring, periodic evaluation of culture through formal employee surveys, and the development of appropriate initiatives including a set of corporate core values, as well as ongoing review of market compensation for personnel with the necessary skills and experience.
Increase the consistency and clarity of the communications of NERC leadership regarding the end-state vision and	VII; Attachment 6, pp. 16. To facilitate effective communications across the ERO Enterprise, in May 2013 the NERC Board of Trustees initiated a practice of meeting twice yearly as a group with all the chairs and

progress of major ERO initiatives.	vice-chairs of the Regional Entities, with a portion of these meetings conducted with the NERC and Regional Entity CEOs also present. Additionally, a NERC-Regional Entity communications working group has been active for several years, coordinating consistent messaging across the ERO Enterprise. Further, NERC and the Regional Entities have coordinated outreach to FERC Commissioners and staff and to Canadian governments. NERC is working to address the areas where improvement is needed.
Make processes for developing documents related to compliance more transparent and open to stakeholder feedback.	II(A)(4); II(C)(2)(a) NERC has taken several steps to address this concern. RSAWs are now developed concurrently with Reliability Standards development projects, allowing for increased coordination among compliance staff and the standard drafting teams and the opportunity for industry comment on the draft RSAWs. Draft RSAWs are to be posted during the formal comment period and prior to the ballot period for the associated Reliability Standards, allowing stakeholders to provide comments or raise concerns at that time. Further, NERC is also engaged in several activities under RAI to enhance transparency and consistency in auditor practices across the ERO Enterprise, including making the *Compliance Auditor Checklist* and *Compliance Auditor Handbook*, as found in the *ERO Enterprise Compliance Auditor Manual*, available to industry.
Increase the specificity of the ERO strategic plan.	VII NERC and the Regional Entities have collaboratively made significant progress in developing a shared, rolling three-year *ERO Enterprise Strategic Plan.* In May 2014, the NERC Board of Trustees approved a series of performance metrics which will be used to assess the overall effectiveness of the ERO Enterprise in addressing risk to the BPS, achieving reliability results, assuring Reliability Standards and compliance effectiveness, and improving risk mitigation and program execution. They include four overarching metrics focused on overall effectiveness in addressing BPS risks and improving reliability. They also include a number of supporting measures that assess the effectiveness of the key operational elements of the ERO Enterprise.
Improve and streamline external communications to	NERC has created a once-a-week bulletin for Reliability Standards announcements, and is working to include compliance

make them more useful and accessible to stakeholders.	activities in this bulletin as well. Additionally RSS feeds have been added to the "NERC Newsroom" webpage enabling stakeholders to subscribe or unsubscribe to the NERC newsletters or NERC headlines. Future releases will include more RSS feeds that will provide stakeholders the opportunity to subscribe or unsubscribe to information on the NERC website, coupled with ongoing enhancements to content and search features.
Continue to work with Canadian entities regarding NERC's efforts to seek recognition in Canada, including preparing and verifying the information in Attachment 1.[5]	III; Attachment 1 – I(6) NERC is actively working with Canadian entities in a variety of ways. NERC participates in the meetings of a trilateral group consisting of regulators from Mexico, FERC, and the Federal-Provincial-Territorial Electricity Working Group (Canada). In addition, each month NERC staff participates in calls to discuss standards drafting efforts and associated governance and committee-related activities. Workshops and organized forums over the course of each year provide dedicated time for outreach and exchange of perspectives. NERC is also working with relevant stakeholders in Canada, including registered entities and applicable government authorities, on increasing visibility of compliance monitoring and enforcement activities that assure reliability in Canada. NERC appreciates the assistance provided by Canadian entities in the preparation and verification of information in the detailed discussion in Attachment 1 regarding NERC's efforts to seek recognition in Canada.
Business Plan and Budget	
Give stakeholders earlier opportunities to provide input for the business plan development process and the business plan. Extend the time by which stakeholders have an opportunity to provide input into the business plan and	Attachment 3 – V(B) NERC and the Regional Entities typically start the BP&B process in the fourth quarter of the second preceding year. The process includes multiple opportunities for stakeholder input, and NERC attempts to provide opportunities for stakeholder input on the *ERO Enterprise Strategic Plan* and the BP&B as early as reasonably possible in the process.

[5] Attachment 1 to the *Five-Year ERO Performance Assessment Report* is titled *Discussion of How NERC Meets the ERO Certification Criteria of 18 C.F.R. §39.3(b)*.

budget (BP&B), and increase the clarity of projected costs.	In the preparation schedule for the 2015 BP&B, policy input for the *ERO Enterprise Strategic Plan* was requested by the NERC Board of Trustees on January 8, 2014 with a response date of January 29, 2014. Meetings with trade associations were held in January 2014 on the *ERO Enterprise Strategic Plan* and in April 2014 on the 2015 BP&B. The Member Representatives Committee (MRC) meetings on February 5, 2014 and May 6, 2014 included further opportunities for policy input. A draft NERC 2015 BP&B was posted on May 16, 2014 for a 45-day stakeholder comment period. A final draft of the 2015 BP&B was posted on July 15, 2014 for a 2-week stakeholder comment period. Additional opportunities for stakeholder comment are provided through multiple scheduled meetings of the MRC BP&B Input Group (described below) and meetings of several NERC standing committees (Operating, Planning, Standards, Critical Infrastructure Protection, Compliance and Certification, and Reliability Issues Steering Committees) to receive input, as well as through opportunities for stakeholder comments in open sessions of the quarterly MRC and NERC Board of Trustees meetings. NERC provided more opportunities for stakeholder input in the 2015 BP&B preparation schedule than was provided for the 2014 BP&B.
Explain how stakeholder input on the BP&B is actually utilized	NERC carefully and thoroughly considers all stakeholder input on the BP&B, whether it is submitted in writing during formal posting and comment periods or in open meetings. Typically, stakeholder comments are not directed to individual detailed line items in the draft BP&B, but rather are primarily directed to the overall amount of increase in the proposed budget for the ERO Enterprise or for certain departments, or the overall assessment increase. In a number of years, NERC has responded to stakeholder concerns about the overall level of budget and assessment increases shown in earlier drafts of the BP&B, by reducing planned expenditures (e.g., through eliminating or deferring specific projects and other initiatives or by reducing planned levels of compensation increases for some or all employee categories) to produce a lower level of expenditures and assessments in the final BP&B. Additionally, in each annual BP&B filing with FERC beginning with the filing for 2009, NERC has included an attachment summarizing stakeholder comments received during development of the BP&B and how NERC addressed or considered the comments. Finally, a number

	of enhancements to NERC's BP&Bs have been the result, in whole or in part, of stakeholder comments, including the provision of greater granularity and more detailed explanations for consultant and contractor expenses and for proposed Information Technology and other information systems and infrastructure projects in the BP&B; and the development and inclusion of long-term (three-year) future budget projections in the BP&B.
Permit greater incorporation of policy input from the MRC into the business plan.	Under the NERC Bylaws, one of the purposes of the MRC is "to provide advice and recommendations to the board with respect to the development of annual budgets, business plans and funding mechanisms, and other matters pertinent to the purposes and operations of the Corporation" (Article VIII, §1). Under Article XIII, §4 of the Bylaws, consultation with the MRC and posting of draft BP&Bs for review and comment by the MRC are mandatory components of the development of the annual BP&B. Obtaining MRC comments and input has always been a part of the BP&B development process; however, over the last three BP&B cycles, steps have been taken to increase MRC input. Specifically, a MRC BP&B Input Group was formed in August 2012 and began to function as part of the development of the 2013 BP&B; the participation of this group has been formalized as a specific mechanism for the provision of MRC input. The BP&B development process now includes a specific schedule of meetings with the MRC BP&B Input Group – for example, the preparation schedule for the 2015 BP&B includes 5 scheduled meetings or conference calls with the MRC BP&B Input Group, as well as 2 scheduled MRC informational session webinars and the regular quarterly MRC meetings. Additionally, as indicated earlier, the NERC Board of Trustees has now made it a regular practice to solicit policy input from the MRC as well as other stakeholder groups, early in the process, on various issues relevant to the *ERO Enterprise Strategic Plan* and the BP&B; the policy input received is then discussed at subsequent meetings of the Board of Trustees. NERC does not believe that prior policy input from the MRC regarding goals has not been taken into account in developing business plans, as suggested by the comment. However, the development of both the rolling three-year *ERO Enterprise Strategic Plan* and the annual BP&B reflects consideration and accommodation of input and comments from numerous stakeholder sources, some of which may be inconsistent or even conflicting, as well as the need to meet NERC's legal, regulatory, and corporate responsibilities. Therefore, it will not necessarily

	be possible to trace specific input from a specific source into specific provisions of the BP&B.
Clarify that certain non-statutory requirements were transitioned out of the NERC BP&B.	Without agreeing or disagreeing that these were non-statutory activities, this comment is correct that the Interchange Distribution Calculator, previously funded by NERC, has been transitioned to the IDC Association, and the E-Tag registry has been transferred to the North American Energy Standards Board; both are no longer funded by NERC. Other reliability-related tools have been transitioned to industry sponsorship and funding. NERC Rule of Procedure Section 1002, as amended during the assessment period, states that NERC will review all tools and services it provides to determine if they can be transitioned to an appropriate industry group or organization. Additionally, NERC will be ending its funding and management of the North American Synchro-Phasor initiative by the end of 2014 as it is transitioned to private sector sponsorship and funding. Finally, the formation of the NATF and NAGF has resulted in those organizations taking responsibility for some educational and collaborative activities that otherwise might have been conducted and funded by NERC.
Provide presentations to stakeholders on NERC's efforts to ensure maximum efficiency in the use of resources. The *Five-Year ERO Performance Assessment* should address reasons for budget increases and NERC's plans to control costs going forward.	NERC strives to explain in each annual BP&B how it is using resources efficiently within the proposed budget. Specific actions that have been taken to reduce budgeted costs and use resources efficiently are described in each BP&B; typically, these actions are at a very granular level (e.g., actions within specific program areas) rather than actions that will impact the efficiency of all aspects of NERC's operations. In addition to the textual discussion in the final BP&B, during the BP&B preparation process, NERC conducts a number of meetings, conference calls and webinars for stakeholders and stakeholder groups to explain the proposed BP&B. These include meetings with trade associations and NERC committees as well as webinars, meetings, and conference calls (such as meetings and conference calls with the Board of Trustees, the Finance and Audit Committee, and the MRC) that are open to all stakeholders. In these meetings, conference calls and webinars, the proposed BP&B is typically reviewed at a more aggregated level with focus on the more significant projects and initiatives impacting cost increases and decreases. There are several specific initiatives that NERC has implemented or is in the process of implementing that have increased or will increase the efficiency of the ERO Enterprise operations. These initiatives have been discussed and described through numerous

	means accessible to stakeholders including in the rolling three-year *ERO Enterprise Strategic Plan*, BP&Bs, CMEP Implementation Plans, and workshops, seminars and webinars, as applicable to each particular activity. NERC will continue to look for additional means to communicate with stakeholders on NERC's efforts to use its resources efficiently, both through giving added focus to this topic in existing presentations and through additional stakeholder communications addressing this topic. NERC respectfully disagrees that a detailed analysis of budget increases over the five-year period and possible future increases is necessary for the *Five-Year ERO Performance Assessment Report*. NERC's annual BP&Bs already provide an annual review of (and opportunity for stakeholder comment on) budget increases from the prior year to the budget year. Each annual BP&B provides an explanation of budget increases (if any) in each of several line items for each program area, with more extensive discussion of more significant cost increase items. The *Five-Year ERO Performance Assessment Report* describes a number of initiatives that NERC has implemented and is continuing to undertake to improve the efficiency of NERC and Regional Entity operations while enhancing BPS reliability, including: (i) the SNOP process and FFT process (which continues to be enhanced); (ii) the RAI and the entire RRM process, all of which are focused on making more efficient use of ERO Enterprise (and stakeholder) resources while focusing resources on the issues and areas that pose the greatest risk to BPS reliability; (iii) the development of common training programs, the *Compliance Auditor Checklist*, and the *Compliance Auditor Handbook*, as found in the *ERO Enterprise Compliance Auditor Manual*, for compliance auditors across all Regional Entities; (iv) the Paragraph 81 project and the Standards Independent Expert Review Panel review of Reliability Standards requirements, which have resulted in the elimination of numerous requirements, thereby reducing the number of requirements that NERC and the Regional Entities must expend resources to monitor; and (v) the risk-based and cost-effectiveness reviews of proposed standards development projects so that resources are not expended on development of standards that will have minimal impact on reliability. The development of new or enhanced, uniform information and data management systems (both internal and user-facing) to be used by the entire ERO Enterprise will also increase efficiencies and

	help to control costs in the future. Additionally, NERC has reorganized departments, such as Reliability Standards, to use personnel more efficiently. By far the most significant component of NERC's BP&B are personnel-related costs, both direct personnel expenses (salaries and benefits) and costs that vary primarily based on the number of personnel (such as travel expense, office space costs, and telecommunications and computing costs). Therefore, as NERC has increased staffing in response to input from FERC and stakeholders indicating the need for more extensive or expeditious activities in specific areas (e.g., faster Reliability Standards development, increased NERC staff support for standard drafting teams, increased oversight of Regional Entity compliance monitoring activities, more expeditious processing of noncompliance items, increased training, education and outreach activities, and additional, focused reliability assessment reports), and has responded to the increased significance of certain reliability risk areas (e.g., cybersecurity), NERC staffing has necessarily increased and therefore budgets have increased. A second, overall area of budget increases has been for new and enhanced IT and other information and infrastructure systems in response to: (i) stakeholder desires for more efficient systems with commonality across Regional Entities; (ii) the need for more efficient NERC and Regional Entity internal business processes; and (iii) the development of new user-facing systems to meet emerging needs such as the Technical Feasibility Exceptions process and the BES definition exceptions process.

Table 2: Stakeholder Comments Concerning Regional Entities

In the following table, (i) the first column contains summaries of key stakeholder comments concerning the Regional Entities; and (ii) the second column lists, where applicable, the specific location within the *Five-Year ERO Performance Assessment Report* where the comment is addressed. Additionally, for most of the stakeholder comments, the second column contains a brief response to the comment. The table is divided into sections that correspond to the broad categories of questions asked in the Stakeholder survey.

Summary of Key Stakeholder Comment About Regional Entities	Where Comment is Addressed
Reliability Standards	
Improve the dissemination of information by providing additional information regarding evolving Reliability Standards.	Attachment 3 – I.A; II.B.2.a[6] Many Regional Entities have committed more resources in order to engage in additional training, education, and outreach activities to assist registered entities with their compliance and enforcement responsibilities. These increased activities have included additional workshops, newsletters to industry, and other direct communications.
Compliance Operations	
Improve the speed and consistency of CIP compliance audits.	Attachment 3 – II.B.2.b An important goal of RAI is to develop standard audit policies and procedures for all Regional Entities to serve as a common baseline approach to compliance audits. NERC and the Regional Entities have developed a standardized *Compliance Auditor Checklist* and *Compliance Auditor Handbook*, as found in the *ERO Enterprise Compliance Auditor Manual*, to ensure consistent application of audit procedures across the ERO Enterprise and is now beginning auditor training on these tools.
Enhance the quality, consistency, and accessibility of compliance training.	Attachment 3 – II.B.2.b; *see also* II.B.2.b.ii-ix (*Guidance and Training for Industry Stakeholders*)

[6] Attachment 3 to the *Five-Year ERO Performance Assessment Report* is titled *NERC Assessment of Regional Entity Delegated Functions*.

	Feedback from registered entities regarding training workshops has generally been positive. To address requests from the industry for an increased level of compliance information, many Regional Entities have committed more resources to training. Training activities during the assessment period have included in-person workshops, webinars, training videos and recordings, compliance update letters, on-site visits, and individualized outreach to registered entities.
Ensure that compliance audits are carried out in an efficient, accurate, consistent, and professional manner, and that the procedures and methodology followed by auditors are clear and ultimately useful to the registered entity.	Attachment 3 – II.B.1.c and d; II.B.2.b During the assessment period, NERC and the Regional Entities have increased training opportunities for Regional Entity audit staffs. Through RAI, NERC and the Regional Entities are working together to enhance the clarity and consistency of audit practices across the ERO Enterprise.
Better communicate to the registered entity how to become compliant.	Attachment 3 – II.B.2.a; *see also* II.B.2.b.ii-ix (*Guidance and Training for Industry Stakeholders*); II.D.2.c.ii-iii – II.D.9.ii-iii (*Ensuring the Timely Mitigation of Violations / Promoting Reliability through Enforcement Philosophy and Practices*) In addition to workshops and webinars intended for a broad stakeholder audience, the Regional Entities offer individualized outreach opportunities to the registered entities within their regions to help facilitate compliance with Reliability Standards. Enforcement and mitigation staff at each Regional Entity also work with registered entities to develop and implement effective, appropriate mitigating activities to both address noncompliance and prevent recurrence.

Increase the quality and consistency of compliance-related IT applications.	Attachment 3 – II.B.2.b.ii-ix (*Compliance Monitoring Tools and Procedures / Maintaining Confidentiality*) The Regional Entities are currently exploring ways to enhance their compliance-related IT applications. Several Regional Entities have implemented enhancements, which are described in the individual assessments.
Streamline self-report and enforcement resolution processes.	Attachment 3 – II.D.1.a and b; *Overview of NERC Activities and Accomplishments in the Five-Year Period* II(C) The Regional Entities have worked with NERC to streamline enforcement processes during the assessment period. NERC and the Regional Entities developed and implemented streamlined enforcement processing mechanisms, such as the SNOP and FFT program, which allowed for a marked improvement in enforcement processing rates. Through regular communication and the oversight activities of NERC, NERC and the Regional Entities work to develop and share efficiency-enhancing process improvements. These improvements include the *ERO Self-Report User Guide* and the aggregation program, which were developed under RAI.
Better articulate the CIP Reliability Standards compliance and performance expectations.	Attachment 3 – II.B.2.a; *see also* II.B.2.b.ii-ix (*Guidance and Training for Industry Stakeholders*); *Overview of NERC Activities and Accomplishments in the Five-Year Period* II.A.4. In addition to their regular training and outreach to registered entities, the Regional Entities are working with NERC to identify challenges and best practices for transitioning to Version 5 of the CIP Reliability Standards. The results of a transition implementation study will inform a report that will be broadly shared among industry and stakeholders.

Ensure that guidance tools like Case Notes, CARs, CANs, etc., are consistent and useful to registered entities, but do not become vehicles to reinterpret or revise Reliability Standards outside of the stakeholder process.	*Overview of NERC Activities and Accomplishments in the Five-Year Period* II.A.4 (*Development of Compliance Assessment Tools Concurrently with Reliability Standards Development*) NERC and Regional Entity staff are coordinating on the development of RSAWs as new Reliability Standards are developed. By creating a uniform understanding of compliance expectations for each Reliability Standard early in the standard development process, the need for interpretations or other forms of compliance guidance should be reduced. NERC has terminated the issuance of CANs as of February 2013.
Consider ways to improve the clarity and utility of RSAWs.	*Overview of NERC Activities and Accomplishments in the Five-Year Period* II.A.4 See response to immediately preceding comment.
Enforcement	
Increase transparency regarding the process by which penalties and sanctions are calculated and assigned, and the reasoning behind the calculation and assignment of those penalties and sanctions.	Attachment 3 – II.D.1.d, II.D.2.d-II.D.9.d (individual Regional Entity *Implementation of Various Aspects of the CMEP*) Each of the Regional Entities has taken steps to increase the transparency regarding its penalty determination processes through the assessment period. Each of the Regional Entities follows the NERC *Sanction Guidelines*, and each penalty is reviewed to ensure consistency with other penalties assessed across the ERO Enterprise for similar violations occurring under similar facts and circumstances.
Streamline and hasten the enforcement process so as to make it more efficient and reduce the cost burden on registered entities.	Attachment 3 – II.D.1.a-b; *Overview of NERC Activities and Accomplishments in the Five-Year Period* II(C)

	The Regional Entities have worked to streamline their enforcement processes during the assessment period. NERC and the Regional Entities developed and implemented streamlined enforcement processing mechanisms, such as SNOP and FFT, which allowed for a marked improvement in enforcement processing rates and reductions in caseloads. Through regular communication and the oversight activities of NERC, NERC and the Regional Entities work to develop and share efficiency-enhancing process improvements. These improvements include the *ERO Self-Report User Guide* and the aggregation program, which were developed under RAI.
Address the backlog in violation processing.	Attachment 3 – II.D.1.b.i-iii; *Overview of NERC Activities and Accomplishments in the Five-Year Period* II(C)(4) By the end of the assessment period, NERC and the Regional Entities processed over 99% of violations discovered from 2007 through 2011 (excluding on hold violations). NERC and the Regional Entities are working to achieve an objective that all violations are processed before reaching 24 months in age. Some Regional Entities achieved this objective as of the end of 2013.
Better communicate why violations occurred so registered entities can learn from them.	Attachment 3 – II.D.2.c.ii-iii–II.D.9.ii-iii (*Ensuring the Timely Mitigation of Violations / Promoting Reliability through Enforcement Philosophy and Practices*); II.B.2.a; *see also* II.B.2.b.ii-ix (*Guidance and Training for Industry Stakeholders*) In the event a registered entity is found to be noncompliant with one or more Reliability Standards, Enforcement and Mitigation staff at the Regional Entity will work with the registered entity to develop and implement effective, appropriate mitigating activities to both address the noncompliance and prevent recurrence.

	Compliance and Enforcement staff at the Regional Entities also conduct workshops, webinars, and individualized outreach opportunities to help facilitate compliance with Reliability Standards.
Expand the use of FFTs.	Attachment 3 – II.D.1.b.iv; *Overview of NERC Activities and Accomplishments in the Five-Year Period* II(C)(1) In 2013, NERC and the Regional Entities worked together to expand the FFT program and implement certain enhancements approved by the Commission. As a result of these enhancements, FFT treatment is now available for a limited pool of possible violations posing a moderate risk to the reliability of the BPS (in addition to possible violations posing a minimal risk). In addition, certain unmitigated possible violations may be processed through the FFT program, so long as mitigation is completed within 90 days from the date the FFT is posted. Additional FFT enhancements may be implemented in the future under RAI.

Enhance consistency regarding enforcement processing across the regions.	Attachment 3 – II.D.1.b.vi; II.D.1.d; *Overview of NERC Activities and Accomplishments in the Five-Year Period* II(C)(4)(a)-(c) NERC and the Regional Entities engage in a number of activities to enhance consistency. For example, each of the Regional Entities have participated in RAI development activities and the multi-region working group on enforcement activities. In addition, NERC conducts oversight activities to facilitate the consistent application of streamlined enforcement processing mechanisms and other enforcement-related processes under the CMEP. Further, NERC and the Regional Entities take steps to promote reasonable consistency in the application of monetary penalties. Each penalty is reviewed to ensure consistency with other penalties assessed across the ERO Enterprise for similar violations occurring under similar facts and circumstances.
Registration and Certification	
Increase the clarity, regional consistency, quality, and overall efficiency of the CFR and JRO process.	Attachment 3 – II.A ; *Overview of NERC Activities and Accomplishments in the Five-Year Period* II.B.1 The JRO and CFR mechanisms are important components of the NERC Organization Registration and Certification program. Amendments to the NERC Rules of Procedure during the assessment period have clarified the operations of both types of registration. In addition, the Regional Entities began using consistent registration forms during the assessment period. As of May 1, 2014, there are 34 JROs and 44 CFRs, which illustrates that numerous entities have been able to utilize these registration options.
Reduce redundancies in the registration and certification processes.	Attachment 3 – II.A ; *Overview of NERC Activities and Accomplishments In the Five-Year Period* II.B

Better communicate the requirements for certification and re-certification. Increase clarity and guidance surrounding how entities are registered by NERC, and respond timely to deregistration inquiries.	During the assessment period, the Regional Entities began using consistent registration forms. In addition, a Regional Entity working group developed a prototype "Common Registration Form" which will provide greater assurance that all entities that should be registered are in fact registered. Two initiatives are underway to improve registration and certification processes. The first pertains to multi-regional registered entities. The second is the risk-based registration effort, which will improve the efficiency with which a Regional Entity is able to process registration activation and deactivation requests.
Reliability Assessment & Performance Analysis Metrics	
Ensure that the Regional Entity self-assessments are consistent by using consistent criteria and trigger points.	Attachment 3 – III.B Each Regional Entity's self-assessment is distributed to Regional Entity members of the NERC Reliability Assessment Subcommittee (RAS) for an in-depth and comprehensive review of the data and information. Peer reviewer comments are discussed with Regional Entity and assessment area representatives, and refinements and adjustments are made, as needed. The Regional Entity self-assessments are then subjected to scrutiny and review by the entire RAS. This peer review process provides an essential check and balance to ensure the validity of the information provided for each assessment. It also provides a mechanism for the members of the RAS to become fully convinced that each Regional Entity self-assessment is accurate, thorough, and complete.
Training, Education, and Personnel Certification	
Increase the availability, quality, and accessibility of training regarding audit preparation and Reliability Standard compliance.	Attachment 3 – II.B.2.a; *see also* II.B.2.b.ii-ix (*Guidance and Training for Industry Stakeholders*); *Overview of NERC Activities and Accomplishments in the Five-Year Period* II.C.2.a. To address requests from the industry for an increased level of compliance information, many

	Regional Entities have committed more resources to training and expanded their training offerings. Training activities during the assessment period have included in-person workshops, webinars, training videos and recordings, compliance update letters, on-site visits, and individualized outreach to registered entities. In addition, under RAI, the Regional Entities are working with NERC to develop and implement improvements to audit processes, including changes in the timing of preparation of RSAWs and development of a common *Compliance Auditor Checklist* and *Compliance Auditor Handbook*, as found in the *ERO Enterprise Compliance Auditor Manual*, which was made available to industry. These improvements provide additional insight for registered entities into how they will be audited and what they can do to prepare.
Event Analysis	
Increase the speed by which Event Analysis information (including lessons learned) is disseminated.	Attachment 3 – IV.A; *Overview of NERC Activities and Accomplishments in the Five-Year Period* II(D)(3) In June 2010, NERC and the Regional Entities created the NERC Event Analysis Working Group (EAWG). The EAWG expended significant efforts to develop an ERO Event Analysis process for use across North America. By integrating industry engagement and the collaborative review of disturbances into the ERO Event Analysis process, the effectiveness, predictability, consistency, and timeliness of the program was increased. Several lessons learned have already been shared with industry. The Event Analysis process is resulting in faster dissemination of information and lessons learned from outage events and other system disturbances than had been occurring through compliance investigations.
Improve the quality of disseminated Event Analysis information by showing relative	Attachment 3 – IV.C

and key emerging risks based on data analyzed through Event Analysis processes and by releasing more meaningful lessons learned.	NERC is considering improvements to increase the timeliness, transparency, and comprehensiveness of dissemination of information relating to Event Analysis and lessons learned.
Better coordinate information requests when NERC and a Regional Entity are involved in an event investigation.	Attachment 3 – IV.C In response to suggestions received during the ERO Event Analysis annual review, NERC is exploring potential solutions (including the possibility of implementing enterprise IT systems) to provide efficiencies in Event Analysis and related reporting processes.
Increase the effectiveness and efficiency of ERO-wide Event Analysis communications, particularly as to when an event is closed out.	Attachment 3 – IV.A; *Overview of NERC Activities and Accomplishments in the Five-Year Period* II(D)(3) NERC and the Regional Entities are continuously refining the ERO Event Analysis process based on experience and as system conditions change.
Stakeholder Communications, Public Relations, and IT	
Make Regional Entity websites more accessible, user-friendly, secure, and useful to registered entities.	Attachment 3 – II.B.2.b.ii-ix (*Guidance and Training for Industry Stakeholders / Maintaining Confidentiality*) The Regional Entities post a number of compliance and technical materials to assist registered entities in their compliance program implementation. In addition, the Regional Entities use encryption and other methods to ensure that information submitted through Regional Entity websites is secure.
Business Plan and Budget	
Increase transparency regarding the funding mechanisms for Regional Entities when they undergo reorganization.	Attachment 3 – V.B. NERC and the Regional Entities have continuously striven for improved transparency and detail in the business plans and budgets. Numerous improvements have been implemented in this regard. To provide ongoing, collaborative oversight of the business planning,

	budgeting, accounting, and financial reporting processes, NERC and the Regional Entities have formed an ERO Finance Group comprised of representatives of NERC and each Regional Entity.

Table 3: Overview of Five-Year and Three-Year Survey

The following table provides comparative statistics concerning the stakeholder survey that was taken in connection with the preparation of the *Three-Year ERO Performance Assessment Report*, in 2009, and the stakeholder survey that was taken in late 2013 in connection with the preparation of this *Five-Year ERO Performance Assessment Report*.

Five-Year Survey	Three-Year Survey
326 registered entity responses	128 registered entity responses
0 trade association or organized group responses	5 trade association or organized group responses
0 regulator, state, provincial, federal or other responses	3 regulator, state, provincial, federal or other responses
0 reliability stakeholder or public responses	6 reliability stakeholder or public responses

Table 4: Stakeholder Average Scores

The remainder of this Attachment summarizes information from the stakeholder survey conducted in October 2013.

Regional Entity	Response Rate (%)	Total Number of Responses	Total Unique NCR IDs
FRCC	33	23	69
MRO	28	38	135
NPCC	21	62	301
RF	22	75	343
SERC	32	74	233
SPP RE	27	39	145
TRE	20	46	225
WECC	20	97	477

Reliability Standards Questions					
	1. Develops Reliability Standards that indicate which BPS owners, operators and users must comply with individual requirements	2. Develops Reliability Standards that have a sound basis in engineering and operations	3. Develops and modifies Reliability Standards in a timely manner giving consideration to the prioritization of reliability objectives	4. Develops an annual *Reliability Standards Development Plan* that is an effective tool to communicate and gather stakeholder input to the proposed scope of work, schedules, and priorities for developing and	5. Communicates information about Reliability Standards, their development, and opportunities for stakeholder participation in an efficient and

				revising Reliability Standards	effective manner
Average Score					
NERC	4.0	3.3	3.2	4	3.8

Compliance Operations Questions					
	1. Provides accessible information about the level of performance necessary to comply with requirements of applicable Reliability Standards	2. Provides accessible information about what documentation and other evidence is needed to demonstrate compliance	3. Conducts audits, investigations, spot-checks and other compliance monitoring methods in a professional, thorough, and efficient manner	4. Utilizes electronic tools and forms that provide for clear, effective, and efficient submittal and handling of compliance information	5. Encourages registered entities to conduct internal self-assessments of compliance and self-report possible violations
Average Score					
NERC	2.1	1.8	1.6	1.4	3.3
FRCC	3.2	3.1	3.7	3.5	4.2
MRO	3.3	3.3	3.8	3.7	4.1
NPCC	3.8	3.6	4.0	4.0	4.2
RF	3.6	3.6	3.6	3.9	4.0
SERC	3.7	3.5	4.1	3.9	4.2
SPP RE	3.4	3.3	3.4	3.6	3.8
TRE	3.7	3.6	4.0	4.0	4.1
WECC	3.6	3.6	3.9	3.8	4.1

Enforcement Questions			
	1. Ensures that possible violations are investigated, assessed and closed in a timely manner	2. Levies penalties and sanctions for the violation of a Reliability Standard that bear a reasonable relation to the risk to reliability the violation presents	3. Levies penalties and sanctions that reflect consideration of the other factors specified in the *Sanction Guidelines*
Average Score			
NERC	1.7	2.1	2.3
FRCC	3.5	3.6	3.4
MRO	2.9	2.8	2.9
NPCC	2.8	2.7	2.8
RF	3.2	3.1	3.2
SERC	2.9	3.2	3.2

SPP RE	2.9	2.4	2.4
TRE	3.2	3.1	3.2
WECC	3.1	2.8	2.8

Registration and Certification Questions			
	1. Establishes adequate criteria to determine which owners, operators, and users of the BPS perform certain reliability functions and should therefore be registered as responsible for complying with Reliability Standards applicable to those reliability functions	2. Has a registration process that is effective in addressing situations in which compliance responsibilities are shared or delegated among entities, such as through the use of CFR or JRO	3. Conducts inquiries in a professional, thorough, and efficient manner for entities applying or submitting changes for certification as Reliability Coordinators, Balancing Authorities, and/or Transmission Operators
Average Score			
NERC	2.5	2.6	1.2
FRCC		3.5	3.2
MRO		3.4	2.8
NPCC		3.3	3.0
RF		3.3	2.8
SERC		3.4	2.5
SPP RE		3.2	2.5
TRE		3.3	2.5
WECC		2.6	2.6

Reliability Assessment Questions		
	1. Effectively communicates reliability assessments to stakeholders, policy makers, and the public, to explain why certain actions are necessary or appropriate to ensure future adequacy and reliability of the BPS	2. Effectively reports on regional self-assessments of electric supply and bulk power transmission reliability, including emerging and long-term reliability issues of specific regional and North American concern
Average Score		
NERC	2.4	2.2

Performance Analysis and Metrics Questions		
	1. Compiles and publishes useful information on performance metrics and benchmarks to observe and understand trends in the reliability and performance of the BPS and in the reliability performance of users, owners and operators, and to highlight areas for potential improvements	2. Identifies reliability performance issues for consideration in the development or modification of Reliability Standards
Average Score		
NERC	2.7	2.7

Training, Education, and Personnel Certification Questions			
	1. Provides effective training to registered entities on complying with Reliability Standards	2. Provides effective training on how to demonstrate compliance to auditors	3. Has an effective program for issuing certification credentials to skilled, trained, and qualified BPS operators, and for the maintenance of those certification credentials
Average Score			
NERC	2	1.8	2.9
FRCC	3.7	3.6	
MRO	3.2	2.9	
NPCC	3.5	3.4	
RF	3.4	3.1	
SERC	3.6	3.4	
SPP RE	3.5	3.4	
TRE	3.8	3.5	
WECC	3.8	3.4	

Event Analysis Questions				
	1. Develops and disseminates timely and useful information about system events and specific reliability risks affecting reliable operation of BPS through the lessons learned processes	2. Effectively uses the Alert Level 2 (Recommendations) and Level 3 (Essential Actions) under Rules of Procedure Section 810 to effectively track specific reliability risks affecting the reliable operation of the BPS	3. Has an Event Analysis program that provides and supports analysis on reliability risks that is useful to the industry and focused on BPS reliability	4. Investigates and analyzes events in an efficient manner, appropriate to the severity of the event
Average Score				
NERC	2.3	1.4	2.7	2.7

FRCC	3.6		3.4	3.3
MRO	3.0		2.9	2.8
NPCC	3.3		3.3	3.4
RF	3.3		3.0	3.1
SERC	3.5		3.3	3.2
SPP RE	3.2		3.1	2.8
TRE	3.6		3.5	3.5
WECC	3.2		3.0	2.9

Critical Infrastructure Protection Questions		
	1. Serves as an effective leader and facilitator of the industry's efforts to identify and protect BPS critical infrastructure, including by identifying and publicizing threats to critical infrastructure	2. Provides cybersecurity alerts that are effective for notifying BPS owners, operators, and users of vulnerabilities and actions to address those vulnerabilities
Average Score		
NERC	2.3	1.7

Stakeholder Communications, Public Relations, and IT Questions			
	1. Provides a public website that is useful in meeting stakeholder needs and provides easy access to information	2. Provides newsletters, conferences, and other stakeholder communications that are effective in providing stakeholders with useful and timely information regarding reliability and ERO/Regional Entity activities	3. Provides effective outreach to all jurisdictional stakeholders, including smaller entities with limited ability to travel to meetings and conferences
Average Score			
NERC	3.3	4.1	3.9
FRCC	3.4	3.6	3.3
MRO	3.4	3.9	3.6
NPCC	3.6	3.8	3.4
RF	3.6	3.9	3.4
SERC	3.6	3.9	3.9
SPP RE	3.4	3.6	3.4
TRE	3.9	3.9	3.8
WECC	3.6	3.9	3.7

Business Plan and Budget Questions		
	1. Provides reasonable opportunity for members and other stakeholders to provide	2. Provides sufficient financial information in support of its business plan and budget and its

	input in the annual business plan and budgeting process	quarterly and annual financial reporting
Average Score		
NERC	2.4	2
FRCC	2.9	2.9
MRO	3.2	3.1
NPCC	2.8	2.7
RF	3.2	3.0
SERC	3.5	3.3
SPP RE	2.8	2.7
TRE	3.4	3.3
WECC	3.0	2.9

Independence and Stakeholder Input Questions				
	1. Retains staff that are independent of BPS owners, operators and users and responsive to the needs of reliability stakeholders	2. Effectively communicates a vision and expectations and provides effective leadership to achieve that vision consistent with the *ERO Enterprise Strategic Plan*	3. Performs statutory functions in a transparent manner with adequate opportunity for stakeholder input	4. Provides fair stakeholder representation in the selection of directors and other decision-making in committees or other subordinate organizational structures
Average Score				
NERC	3.8	2.3	3.7	3

FEDERAL ENERGY REGULATORY COMMISSION
DOCKET NO. RR14-___

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

ATTACHMENT 5

TO

FIVE-YEAR ELECTRIC RELIABILITY ORGANIZATION PERFORMANCE ASSESSMENT REPORT

STATUS OF AREAS FOR IMPROVEMENT IDENTIFIED IN THE ORDER ON THE THREE-YEAR ERO PERFORMANCE ASSESSMENT

JULY 21, 2014

Attachment 5: Status of Areas for Improvement Identified in the Order on the Three-Year ERO Performance Assessment

Citation to Order on the Three-Year ERO Performance Assessment (¶)	Areas for Improvement	Status Update[1]
100-102	Believes that NERC (along with its stakeholders) should prioritize those Reliability Standards projects that, in its expert judgment, are the most critical to the reliability of the Bulk-Power System (BPS).	The NERC Board of Trustees has established the Reliability Issues Steering Committee (RISC) to set priorities on issues of importance to the BPS, including the development of Reliability Standards. *See Overview of NERC Activities and Accomplishments in the Five-Year Period*, page 28.
104	Reach out to registered entities to provide expert volunteers on Reliability Standards drafting teams and continue streamlining NERC's procedure to aid in reducing the strain on industry resources overall.	NERC has increased focus on outreach to stakeholders for participation in the Reliability Standards development process. At the end of May 2014, 858 stakeholder representatives had registered their eligibility to vote on proposed Reliability Standards as members of the Registered Ballot Body, and in 2013 alone NERC hosted 43 Reliability Standard industry webinars attended by an average of 360 participants. During the last six months of 2013, standard drafting teams (SDTs) and five-year review teams made up of 195 industry volunteers participated in 60 team meetings to advance Reliability Standards development activities. NERC has also made revisions to the *Standard Processes Manual*, which were approved by the Commission on June 26, 2013. These revisions have, among other things, led to a substantial decrease in the time required to revise an existing Reliability Standard or to develop a new one. This reduction in time provides registered entities with increased flexibility in staffing SDTs due to the reduced time commitment.

		See Overview of NERC Activities and Accomplishments in the Five-Year Period, pages 5, 25.
108	NERC must clearly demonstrate that any proposed elimination of a requirement does not diminish the reliability and enforceability of the existing Reliability Standard.	In the first quarter of 2013, NERC assembled the Reliability Standards Independent Experts Review Panel (IERP) consisting of five independent industry experts and a sixth participant from the Commission. At the end of its review in August 2013, the IERP recommended (among other things) the retirement of 147 existing Requirements of Reliability Standards. In making this determination, the IERP assessed whether a requirement: (i) did not support a reliability principle; (ii) met the Paragraph 81 criteria for retirement; or (iii) was better suited as a guideline rather than as a part of a Reliability Standard. The IERP's recommendations set the course for delivering high quality, results-based Reliability Standards with sustainable requirements. For the remaining requirements that the IERP did not recommend for retirement, the IERP applied content and quality criteria to examine whether they were steady-state or needed additional work. The IERP evaluated whether these remaining requirements addressed a risk to reliability by examining: (i) the ranking developed by the NERC RISC; (ii) the violation risk factor (VRF) for each requirement; and (iii) the IERP members' own professional judgment The P 81 initiative identified three layers of criteria to determine whether a requirement should be recommended for retirement. These criteria were identified in a technical

[1] Status update references made to previous sections of this *Five-Year ERO Performance Report* include: (i) *Overview of NERC Activities and Accomplishments in the Five-Year Period*; (ii) Attachment 1: *Discussion of How NERC Meets the ERO Certification Criteria of 18 C.F.R. §39.3(b);* and (iii) Attachment 3: *NERC Assessment of Regional Entity Delegated Functions.*

		whitepaper dated December 20, 2012. The Commission issued an order on November 21, 2013 approving the retirement of 34 Requirements and sub-Requirements within 19 Reliability Standards. *See Overview of NERC Activities and Accomplishments in the Five-Year Period*, pages 14-17, 17-19.
103	NERC and the Regional Entities should also plan to complete the fill-in-the-blank Reliability Standards, which remain pending from Order No. 693. We agree with NERC that setting priorities regarding fill-in-the-blank standards is an issue that should be resolved jointly by NERC and the Regional Entities.	NERC and the Regional Entities have determined that replacing the fill-in-the-blank Reliability Standards with continent-wide Reliability Standards is the optimal approach to addressing outstanding fill-in-the-blank Reliability Standards. NERC has been steadily working to complete revisions to replace fill-in-the-blank Reliability Standards with continent-wide versions. These revisions have been completed for Reliability Standards in four areas: (1) Emergency planning for system restoration and blackstart; (2) Data for steady state and dynamic system modeling; (3) Transfer capability requirements; and (4) Underfrequency load-shedding programs. Revisions are in progress at the time of this writing for Reliability Standards in five additional areas: (1) Analysis and mitigation of protection system misoperations (two projects, one scheduled for completion in 2014 and one in 2015); (2) Undervoltage load-shedding (scheduled for completion in early 2015); (3) Facility connection requirements (scheduled for completion in 2014);

		(4) Disturbance monitoring (scheduled for completion in 2014); and (5) Data for modeling demand (scheduled for completion in 2014). Once these in-progress projects are completed, all of the fill-in-the-blank Reliability Standards will have been revised through a Commission-approved standards development process.
85	Renews the directive that NERC submit quarterly reports on Reliability Standards development for an additional three years, with additional detail of required analysis. The quarterly reports should include: (i) the time required to complete projects; (ii) the time required to complete projects initiated in response to NERC's urgent action progress; and (iii) the time required to complete projects in response to Commission directives. The analysis should include data on the time required for each stage of the process.	NERC has been filing quarterly analyses of Reliability Standards voting results in Docket No. RR06-1 since May 2007. NERC continued to file these quarterly reports, including the additional information directed in the Order on the Three-Year ERO Performance Assessment, through and including the fourth quarter of 2013.
107-112	The Commission provided guidance regarding NERC's initiative to transition to results-based Reliability Standards. 107-108: the revised Reliability Standards should incorporate the Commission's	During the assessment period, NERC launched several initiatives designed to evolve the Reliability Standards into "steady-state," which means a stable set of clear, concise, high-quality, and technically sound Reliability Standards. Several important components of this evolution are: (i) the results-based Reliability Standards initiative; (ii) the P 81

	directives from prior orders that address the substantive performance goals of the BPS. 109: expanded background sections, purpose sections, or explanations of intent, should not contradict or seek to supersede or interpret the requirements within a Reliability Standard. 110: a requirement cannot be retired without its associated reliability benefit being addressed fully in another requirement or Standard. 111: revised Reliability Standards should include objective language rather than subjective modifiers, and should not include language requiring NERC or a Regional Entity to assess whether a registered entity intended to violate a Standard, nor whether a registered entity failed to perform due to, for example, negligence or human error. 112: revised Reliability Standards should not reduce BPS reliability from that which would be required by the existing approved Standards.	project; (iii) changes to the *Standard Processes Manual*; (iv) reorganization of the NERC Standards department; and (v) the work of the IERP. 107-108: Addressing Commission directives relating to Reliability Standards is a major priority to facilitate the transformation to steady-state Reliability Standards. As of December 2012, there were 191 outstanding Commission directives that were related to Reliability Standards development. More than half of the total number of Commission-issued directives were addressed during 2013. At the February 2014 meeting of the NERC Standards Oversight and Technology Committee (SOTC), it was reported that 128 directives had been addressed by the end of 2013, with 107 remaining. NERC anticipates that 90% of Commission directives issued to date will be resolved between the end of 2014 and the first half of 2015. *See Overview of NERC Activities and Accomplishments in the Five-Year Period*, page 12. 109: The NERC *Standard Processes Manual* explicitly states that "[t]he only mandatory and enforceable components of a Reliability Standard are the: (1) applicability, (2) Requirements, and the (3) effective dates. The additional components are included in the Reliability Standard for informational purposes, to establish the relevant scope and technical paradigm, and to provide guidance to Functional Entities concerning how compliance will be assessed by the Compliance Enforcement Authority."

		See Section 2.5 of the NERC *Standard Processes Manual*, Appendix 3A to the NERC Rules of Procedure. 110: The IERP works in conjunction with the RISC to ensure requirements are not recommended for retirement so as to leave gaps in reliability. Additionally, NERC systematically manages the development of new Reliability Standards and revisions to standards, in areas of highest need and importance, through its rolling three-year *Reliability Standards Development Plan* (RSDP). The RSDP is revised annually and identifies and prioritizes Reliability Standards development projects in the immediate three-year time horizon, taking into account, among other information, perceived gaps in the Reliability Standards, proposals for closing those gaps, and timing priorities for standards development projects. *See Overview of NERC Activities and Accomplishments in the Five-Year Period*, pages 14-17, 85. 111: The IERP applies content and quality criteria when assessing whether standards are steady-state or need revisions. Additionally, Section 4.6 of the NERC *Standard Processes Manual* requires that NERC Standards staff conduct a quality review of the Reliability Standard, implementation plan, and VRFs and violation severity level (VSLs) in parallel with the development of the Reliability Standard and implementation plan, to assess whether the documents are within the scope of the associated standard authorization request (SAR), whether

		the Reliability Standard is clear and enforceable as written, and whether the Reliability Standard meets the criteria specified in NERC's Benchmarks for Excellent Standards and criteria for governmental approval of Reliability Standards. Item #4 of NERC's *Ten Benchmarks of an Excellent Reliability Standard* requires that "[e]ach performance requirement shall be stated so as to be objectively measurable by a third party with knowledge or expertise in the area. Each performance requirement shall have one or more associated measures used to objectively evaluate compliance with the requirement. If performance can be practically measured quantitatively, metrics shall be provided to determine satisfactory performance." *See Overview of NERC Activities and Accomplishments in the Five-Year Period*, pages 15-16; Section 4.6 of the NERC *Standard Processes Manual*, Appendix 3A to the NERC Rules of Procedure; and *Ten Benchmarks of an Excellent Reliability Standard*, available at: http://www.nerc.com/pa/Stand/Resources/Documents/10BenchmarksofExcellentReliabilityStandards.pdf. 112: Section 4.6 of the NERC *Standard Processes Manual* requires that NERC Standards staff conduct a quality review of the Reliability Standard, implementation plan, and VRFs and VSLs in parallel with the development or modification of the Reliability Standard and implementation plan, to assess whether the documents are within the scope of the associated SAR, whether the Reliability Standard is clear and enforceable as written, and whether the Reliability Standard meets the criteria specified in NERC's Benchmarks for

		Excellent Standards and criteria for governmental approval of Reliability Standards. *See* Section 4.6 of the *NERC Standard Processes Manual*, Appendix 3A to the NERC Rules of Procedure.
102	NERC should determine whether there are new or modified Reliability Standards that would address identified gaps that may belong in the high priority group.	Two of the recommendations made by the IERP when it presented its report to the NERC Board of Trustees in August 2013 were that NERC address seven areas (high-level gaps) not currently addressed by the Reliability Standards, and complete standards development projects to address gaps within individual requirements. The IERP also made recommendations regarding compliance monitoring, prioritization for addressing the identified gaps, using risk to determine whether a future standard is needed, and use of the IERP's identified criteria to determine the quality and content as future standards are developed. The potential reliability gaps identified by the IERP were evaluated by the RISC and assigned in some cases to active drafting projects. The IERP recommendations that apply to Reliability Standards that were not part of active drafting projects were assigned to teams that conduct periodic reviews of Reliability Standards in the future for consideration. Additionally, NERC systematically manages the development of new Reliability Standards and revisions to Reliability Standards, in areas of highest need and importance, through its rolling three-year RSDP. The RSDP is revised annually and identifies and prioritizes Reliability Standards development projects in the immediate three-year time horizon, taking into account, among other information, perceived gaps in the Reliability Standards, proposals for

		closing those gaps, and timing priorities for standards development projects. *See Overview of NERC Activities and Accomplishments in the Five-Year Period*, pages 15-17, 85.
74	Urge NERC to take measures, including hiring staff with the technical capability to independently advise the NERC Board of Trustees regarding the substantive content of a proposed Reliability Standard.	Although much of the work in the Reliability Standards development process is performed by committees and task groups comprised of volunteer technical experts, significant NERC professional staff resources are needed to facilitate and coordinate the work of industry volunteers, to administer the process and help ensure that it functions efficiently, and to provide input to support development of technically sound standards. NERC has budgeted 25.92 full-time equivalents (FTEs) for the Reliability Standards Program for 2014, which is a slight decrease of 0.58 FTEs from the 2013 budget and reflects the application of the 4% personnel attrition. In accordance with its 2013 business plan and budget, NERC has added 3 positions in the Reliability Standards Program in 2013. NERC has improved the composition of SDTs by enhancing the selection process to identify, for each project, the necessary technical, writing, and project management expertise to form a balanced team that will foster improved effectiveness and enhanced efficiency. In addition, SDTs now receive increased NERC staff support, including dedicated legal support for each project. Each standard development project is staffed by a lead standard developer, and many projects have a second supporting standard developer. Standard developers provide project management and facilitation experience as well as additional skills,

		including technical writing, legal skills, and outreach/ consensus-building skills, to the SDT, which contributes to the development of high-quality Reliability Standards. Additionally, Section 4.6 of the NERC *Standard Processes Manual* requires that NERC Standards staff conduct a quality review of the Reliability Standard, implementation plan, and VRFs and VSLs in parallel with the development of the Reliability Standard and implementation plan, to assess whether the documents are within the scope of the associated SAR, whether the Reliability Standard is clear and enforceable as written, and whether the Reliability Standard meets the criteria specified in NERC's Benchmarks for Excellent Standards and criteria for governmental approval of Reliability Standards. Item #5 of NERC's *Ten Benchmarks of an Excellent Reliability Standard* requires that "[e]ach reliability standard shall be based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in the particular field." *See NERC 2014 Request for Acceptance of Business Plan and Budget*, page 42, Docket No. RR13-9-000; *Overview of NERC Activities and Accomplishments in the Five-Year Period*, pages 31-32; Section 4.6 of the NERC *Standard Processes Manual*, Appendix 3A to the NERC Rules of Procedure; and *Ten Benchmarks of an Excellent Reliability Standard*, available at: http://www.nerc.com/pa/Stand/Resources/Documents/10BenchmarksofExcellentReliabilityStandards.pdf.
152	Encourages NERC to intensify its efforts to provide additional oversight and guidelines to	

	assist registered entities in accurately determining that an asset is critical to the BPS (critical cyber asset identification).	The CIP Version 4 and 5 Reliability Standards move away from the use of the registered entities' risk-based assessment methodology in the identification of critical cyber assets. In Order No. 791, the Commission approved NERC's proposed implementation plan for CIP Version 5 to bypass CIP Version 4 and move directly to CIP Version 5. Recognizing that registered entities are in various stages of implementation of CIP Versions 3 and 4, NERC addressed the need for flexibility as well as the need to identify and address the associated transition challenges for the industry through guidance. *See Overview of NERC Activities and Accomplishments in the Five-Year Period*, pages 34-36; and *Cybersecurity Standards Transition Guidance*, available at: http://www.nerc.com/pa/comp/Resources/ResourcesDL/Cyber%20Security%20Standards%20Transition%20Guidance%20(Revised).pdf.
154	NERC's proposed action item for "fast-track" interpretations of CIP Reliability Standards lacks specificity. NERC states that this process would not require implementation of the full existing Reliability Standards development process, and could improve efficiency without sacrificing quality, but otherwise NERC does not provide any details how it would implement this proposal. While we support efforts to provide greater guidance on CIP	A CIP-specific fast-track process for interpretations of CIP Reliability Standards has not been developed during the assessment period. However, the revisions to the *Standard Processes Manual* approved by the Commission on June 26, 2013, included a waiver provision that allows for modifications to the Reliability Standards development process for good cause, with five days' notice and reporting of the exercise of a waiver to the NERC SOTC. This waiver provision could be used to fast-track the development of an interpretation of a Reliability Standard, including a CIP Reliability Standard.

	implementation, we are concerned whether "fast track" interpretations will provide the consistency, clarity and transparency for meaningful assistance to entities that must comply with the CIP Reliability Standards. If NERC develops this proposal, NERC should submit it to the Commission for review, possibly in the form of a petition for approval of modifications to NERC's Rules of Procedure.	*See Overview of NERC Activities and Accomplishments in the Five-Year Period*, page 24.
169	Regarding Event Analysis, directs NERC to establish criteria it will use to select a subset of events, which should focus on those with the highest impact to reliability, to provide important "lessons learned" and submit the criteria in the informational report.	NERC has developed a voluntary Event Analysis process, including criteria to categorize events, that delivers quality, timely and actionable lessons learned to registered entities. Development of the Event Analysis process was led by the Event Analysis Subcommittee (EAS), a cross-functional group of industry experts. The Event Analysis process begins with a registered entity making an initial assessment of an occurrence and determining if the occurrence falls within one of five qualifying event categories. The event category is determined by weighing the level of significance of a qualifying event and its impact on the interconnected BPS. After a qualifying event occurs, the applicable Regional Entity holds a planning meeting with all involved parties, including other registered entities. If a qualifying event is categorized as Category 3 or higher, the registered entity will prepare an Event Analysis Report (EAR), in which the registered entity describes the sequence of events and identifies causal factors and appropriate corrective actions. The registered entity then submits the EAR to the applicable Regional Entity or Entities for review, and then to NERC.

		The registered entity, in collaboration with the ERO, drafts the proposed lessons learned from the event and submits them to the applicable Regional Entity. Once the event analysis is complete, NERC shares any lessons learned with industry by publishing them as soon as practical. NERC staff analyzes EARs to identify reliability risks, trends, and potential gaps in Reliability Standards, compliance, and other programs. NERC also reviews the EARs to assign descriptive cause codes, which assist in identifying trends and corrective actions that will prevent recurrence of similar events. Since initial implementation of the Event Analysis process in 2010, there have been more than 388 qualified events reported to the ERO and more than 77 lessons learned, including 14 published in 2013. *See Overview of NERC Activities and Accomplishments in the Five-Year Period*, pages 68-71.

170-171, 173-178	170: Directs NERC to work with the Regional Entities to ensure that they provide to Commission staff sufficient and timely information on each event. NERC must report on steps it will take to implement this directive in the informational report. 171: Directs NERC to develop communication protocols between NERC, the Commission and the Regional Entities for use during events and report on its progress in the informational filing. 174: If a Compliance Violation Investigation (CVI) is initiated, it should be conducted concurrently with an Event Analysis and both processes should begin as soon as possible to the extent necessary. 175: maintain the respective focuses of the CVI and Event Analysis to ensure independence of the roles each mechanism is designed to fulfill. 176: In order to create more efficiency in the event analysis and CVI processes, all event analysis materials obtained by the event analysis team, including requests for information and responses, should be sent, at the same time as issued or collected, to the	170 - 171: NERC staff compiles and provides a daily summary of newly reported qualifying events to FERC staff, NERC's Event Investigation group under Compliance Operations, and Regional Entity situational awareness and event analysis points of contact. Event status is reviewed in a biweekly conference with NERC and FERC staff, and in a separate weekly conference call with NERC and Regional Entity staff. 174 - 178: Compliance Investigations (formerly CVIs) are governed by Section 3.4 of the *Compliance Monitoring and Enforcement Program* (CMEP), Appendix 4C to the NERC Rules of Procedure. Event Analysis is governed by Sections 807 and 808 of the NERC Rules of Procedure, along with Appendix 8. These are two separate processes within NERC. Additionally, widespread use of mechanisms like the voluntary Event Analysis process has in practice greatly reduced the need to initiate formal Compliance Investigations following events. *See Overview of NERC Activities and Accomplishments in the Five-Year Period*, pages 68-71.

	compliance staff in each applicable Regional Entity and to NERC compliance staff. These materials, insofar as they relate to a U.S. registered entity, also should be available to Commission staff upon request. 177: Any communication between an event analysis team and a corresponding CVI team generally should be one-way only: from the event analysis team to the CVI team. An exception to this practice would be appropriate only for factual information collected by a CVI team that bears on an important industry advisory that the event analysis team would make (or recommend that NERC make) as part of an initial event analysis determination. 178: NERC shall report on the steps it has taken to clarify the interface between event analyses and compliance activities, including Compliance Investigations, in response to the Commission's guidance in the informational filing.	
126	Directs NERC to continue its oversight of Regional Entity audits with NERC staff that are technically proficient.	As outlined in the NERC Rules of Procedure and the Regional Entity Delegation Agreements, NERC is responsible for oversight of the Regional Entities compliance monitoring program. NERC restructured its oversight process to include a participatory role during Regional Entity compliance. In addition to oversight engagements, NERC has developed the Key Reliability Standard Spot Check (KRSSC), performs

		capability assessments of the Regional Entities, reviews reports submitted by the Regional Entities and conducts two workshops per year in addition to other auditor and lead auditor training. The KRSSC is a study of a single Reliability Standard and a sampling multiple audits across all eight Regional Entities to determine consistency of approach. The results of the study are then provided to the regions to identify improvement opportunities. Starting in 2012, NERC began the process of reviewing the background, education and credentials of the regional compliance auditors and providing feedback to Regional Entities. NERC reads each audit report submitted by the Regional Entities prior to posting to FERC. NERC conducts auditor workshops, performs lead auditor training and provides resources to enhance the consistency of auditor practices across the Regional Entities as well as to improve the technical proficiency of those NERC staff that provide oversight of the Regional Entities' compliance monitoring activities. Finally, NERC participates in the ERO and Compliance and Enforcement Management Group (ECEMG) on a monthly basis where audit activities and projects that improve audit processes and identify opportunities to drive consistency are discussed. *See also* Sections 402 and 403 of the NERC Rules of Procedure; and Attachment 3, pages 16-21.
127	Directs NERC and Regional Entities to have their staff, and Commission staff where applicable, discuss the appropriate role of	Section 3.1.5.3 of the CMEP defines who may participate as an observer in a Regional Entity compliance audit of a Registered Entity. This section also stipulates that

	observers during their pre-audit meetings or conferences.	"Compliance Audit observers and attendees are not Compliance Audit team members and do not participate in conducting the Compliance Audit or in making Compliance Audit findings and determinations." *See* Section 3.1.5.3 of the CMEP, Appendix 4C to the NERC Rules of Procedure.
220	Direct NERC to explain how it would implement risk-based approaches to compliance activities and at the same time complete its currently-required audit cycles.	A key, strategic transformation that NERC, in collaboration with the Regional Entities and stakeholders, embarked upon during the assessment period is the construction of a risk-based model for compliance monitoring and enforcement. This risk-based approach enables NERC to focus ERO and industry resource investment on the most important issues to BPS reliability. *See Overview of NERC Activities and Accomplishments in the Five-Year Period*, pages 50-62.
153	NERC should ensure that there is quality, uniformity and consistency amongst the Regional Entities when conducting compliance audits and spot checks relating to CIP Reliability Standards. NERC should consider the worthiness of an ongoing "accreditation" of qualified auditor candidates through continued education. A program that establishes the requisite level of knowledge and skills needed to maintain necessary levels of technical expertise on a continuous basis should be the goal of the CIP	The NERC CIP audit staff works closely with the Regional Entity CIP staff and provides guidance to the ERO CIP Auditors. NERC provided direct feedback in the past on audit reports and has participated in post-audit phone calls to review best practices, lessons learned and staff qualifications. In order to share best practices and promote consistency, NERC has utilized Regional Entity working groups such as the CIP Compliance Working Group (CCWG) and the ECEMG to discuss technical and policy CIP issues. *See also Overview of NERC Activities and Accomplishments in the Five-Year Period*, pages 53-54, 61-62, for a discussion of the *ERO Enterprise Compliance Auditor Manual*, which

	audit program. These qualifications should be designed to verify the knowledge and skills of the auditor in the area of CIP, control systems and information technology.	includes the *Compliance Auditor Handbook* and *Compliance Auditor Checklist*, as well as auditor qualifications.
118	We suggest that NERC and Regional Entities consider providing ongoing training for their compliance auditors on effective auditing techniques. We expect that NERC's establishment of a Regional Operations Group that focuses on auditors will rapidly improve audit consistency and performance.	As part of its Compliance Operations function, NERC is responsible for supporting the development of qualified and trained compliance operations and auditing staffs at both NERC and the Regional Entities. In addition to the development of a common set of auditor qualifications, NERC ensures the proper qualifications of personnel for auditing and other essential compliance roles through training. *See Overview of NERC Activities and Accomplishments in the Five-Year Period*, page 62.
121	Encourages NERC to continually review its RSAWs to improve their quality and usefulness.	Prior to 2013, NERC developed RSAWs after regulatory approval of a Reliability Standard and at least six months before the Reliability Standard's enforcement date. Today, RSAWs are written concurrently with new Reliability Standard development projects. Each Reliability Standards project is assigned dedicated staff support and led by compliance. NERC compliance staff are coordinating with Regional Entity staff. This increased and ongoing coordination will help ensure that standard drafting teams, compliance staff and RSAWs are aligned with the intent of Reliability Standards, thereby increasing the quality and usefulness of these documents *See Overview of NERC Activities and Accomplishments in the Five-Year Period*, pages 19-21.

180	Directs NERC to continue developing scenario analysis in the long-term reliability assessments. The Commission requires NERC to update its reliability assessment protocols to establish a requirement for an annual scenario analysis and to file this update in the informational filing.	The latest version of the NERC *Reliability Assessment Guidebook* is version 3.1 (dated August 2012). This version was approved by the NERC Planning Committee in June 2012. *See* http://www.nerc.com/comm/PC/Pages/Reliability%20Assessment%20Subcommittee%20(RAS)/Reliability-Assessment-Guidebook.aspx. This version makes more explicit the requirement for an annual scenario analysis to be included in all future long-term reliability assessment (LTRA) reports. Since 2009, the following LTRAs include scenario analyses: • *2009 Long-Term Reliability Assessment* • *2010 Long-Term Reliability Assessmen*t • *2011 Long-Term Reliability Assessment* • *2012 Long-Term Reliability Assessment* Additional scenarios completed as part of the Reliability Assessment program in support of the LTRA: • *2013 Special Reliability Assessment: Accommodating an Increased Dependence on Natural Gas for Electric Power*: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_PhaseII_FINAL.pdf. • *2011 Potential Impacts of Future Environmental Regulations:* http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/EPA%20Section.pdf.

		• *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations:* http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/EPA_Scenario_Final_v2.pdf. • *2010 Special Reliability Scenario Assessment: Potential Reliability Impacts of Swift Demand Growth After a Long-Term Recession:* http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Swift_Scenario_Aug_2010.pdf. • *2010 Reliability Impacts of Climate Change Initiatives: Technology Assessment and Scenario Development:* http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/RICCI_2010.pdf. *See also Overview of NERC Activities and Accomplishments in the Five-Year Period*, pages 71-73.
183	Directs NERC to develop a plan to address capacity and energy in its reliability assessment methodology and a timeline for executing the plan, and submit the plan and timeline as part of the 2011 LTRA and file its preliminary plan and timeline in the informational filing.	NERC implemented probabilistic assessments in the LTRA in 2012 with a trial phase based on voluntary participation occurring in 2011. A detailed plan was included in the 2011 LTRA. In summary, the plan includes the following milestone dates: (1) Request for participation in voluntary trial period (March 2011); (2) Draft methods due to NERC (May 2011); (3) Results of 2011 study (October 2011); (4) Trial view complete (March 2012);

		(5) 2011 trial results to be included in 2012 LTRA (October 2012); (6) Request for full participation (March 2012); and (7) 2012 results to be included in 2013 LTRA (October 2013). Additionally, appropriate modifications were made to NERC's *Reliability Assessment Guidebook* to reflect these changes in the reliability assessment process. NERC completed the "Pilot" assessment in July 2011. *See* NERC's *Pilot Probabilistic Assessment* (dated June 2012), available at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012_ProbA.pdf. NERC completed the first NERC-wide probabilistic study using the 2012 LTRA reference case in June 2013. *See NERC Probabilistic Assessment*, available at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_2012_Probabilistic_Assessment_Final.pdf. These probabilistic assessments will be completed on a biannual basis. *See* NERC's *2013 Long-Term Reliability Assessment* published in December 2013, available at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013_LTRA_FINAL.pdf.
185	Directs NERC to consider establishing permanent databases that could be automatically populated with: (i) new	NERC and the Regional Entities are working on the development of the Reliability Assessment Data System (RADS). While this automated data system is still under

	transmission projects data from the Regional Entities; (ii) generation interconnection queue data; and (iii) other data relevant for reliability assessment. The Commission requires NERC to discuss the feasibility of this improvement, and to the extent databases covering this information already exist, discuss how to better utilize or integrate that information into the reliability assessments in the informational filing.	development, significant improvements to data collection and validation have already been made at the Regional Entity level to support RADS in 2014. The NERC Board of Trustees has also approved mandatory data reporting concerning conventional generating units, transmission outages, and demand response availability. NERC collects this data using its Generating Availability Data System (GADS), Transmission Availability Data System (TADS), and Demand Response Availability Data System (DADS) databases. This unique series of databases is used to collect, record, and retrieve operating information tracking, reporting, analyzing, and improving the reliability performance of the BPS. Regional Entity staff work with NERC staff to ensure the data submitted by entities is timely, complete, and accurate. *See* Attachment 3, pages 143, 145.
57	NERC should continue to seek recognition in Canada and Mexico, as appropriate and keep the Commission informed about the status of those efforts.	NERC continues to engage in substantial efforts to gain and maintain recognition as the ERO in Canada and Mexico. In Canada, where by its constitution the regulation of electricity is primarily within the jurisdiction of each province rather than the national government, NERC's activities to obtain and maintain recognition are conducted on a province-by-province basis. Depending on the particular circumstances of each province, NERC has gained recognition through statutes or other provisions of provincial law, or through a memorandum of understanding with appropriate entities in the province.

		With respect to Mexico, the Comisión Federal de Electricidad (CFE), through the Centro Nacional de Control de Energia (CENACE), and the Area de Control Baja California (ACBC), have entered into a membership and operating agreement (MOA) with WECC. The MOA provides for WECC to assist CENACE and ACBC in monitoring compliance by "Designated Entities" (the Mexican equivalent of U.S. registered entities) with Mexico Reliability Standards for Baja California, Mexico. CENACE has approved a total of ten Mexico Reliability Standards. Pursuant to the MOA, WECC monitors compliance with Mexico Reliability Standards, but does not have enforcement or registration (designation) authority for CFE. WECC provides compliance monitoring, reviews proposed and completed mitigation plans, and provides assessment recommendations with respect to alleged violations. *See Overview of NERC Activities and Accomplishments in the Five-Year Period*, pages 90-91. *See* Attachment 1, pages 34-52.
195	Directs NERC to include a report in the informational filing detailing the feasibility of establishing a NERC-led Strategic Planning initiative utilizing multiple year budgets.	NERC and the Regional Entities jointly develop a three-year rolling *ERO Enterprise Strategic Plan* which includes goals, objectives and deliverables over the planning period and is used in the development of each entity's business plan and budget. The development and implementation of these common formats and methodologies has helped to continuously improve the efficiency of the business plan and budget preparation process and enabled NERC and Regional Entity financial and accounting staffs and senior management to devote greater attention to more substantive budget issues.

		See Attachment 3, pages 155-156.
138, 217	138: Agrees that NERC should develop performance metrics that help to ensure consistent implementation of the compliance enforcement process across the Regional Entities. 217: Agree that the development of reasonable metrics for assessment of the Regional Entities' performance of their compliance functions will increase efficiency of the enforcement process, provide incentives for effectively, timely handling of Regional Entity caseloads, and furnish important data for the next Performance Assessment.	NERC and the Regional Entities continue to focus efforts on the development of a comprehensive and interrelated suite of metrics. Through the Enforcement Functional Group (EFG, formerly ESMWG) forum, NERC and the Regional Entities have worked together to develop a set of enforcement metrics for tracking of the ERO key compliance enforcement activities. A list of final metrics was agreed upon and a set of common parameters (i.e. business rules) was developed to ensure that metric measurements by NERC and the Regional Entities remained consistent. Parameters agreed upon included violation start date, dismissal date, violations active and in inventory among the Regional Entities and NERC. NERC and the Regional Entities developed four metrics that measure the performance of NERC and each of the Regional Entities with respect to enforcement processing. These metrics are as follows: (i) Caseload Index; (ii) Violations in Inventory; (iii) Violation Aging; and (iv) Mitigation Activity Aging. Future initiatives can take up discussion of additional metrics to add to this initial set, particularly in the areas of measuring enforcement quality and effectiveness. (1) The Caseload Index is a metric that computes the number of months that it would take to clear the violations that are either in the Regional Entity's inventory, NERC's

		inventory based upon the respective average monthly processing rate over the preceding twelve-month period. This metric is useful in evaluating the efficiency of processing violations over time. (2) The Violations in Inventory metric is related to the Caseload Index but is also reported separately. It shows how many violations are in the ERO caseload. Month to month comparisons of violations in inventory can show how the workload of each Regional Entity, NERC, and ERO is changing. (3) The Aging metric identifies where older violations, which have not been filed with FERC or otherwise resolved, are located. The Violation Aging chart, which represents this metric graphically, takes all violations in the ERO inventory and shows by region how many violations were discovered in each year from 2007 to 2013. (4) The fourth metric, Mitigation Activity Aging, identifies the status of mitigation activity based upon the age of violations. NERC's BOTCC receives quarterly updates on these enforcement metrics. The latest update was presented to the BOTCC in May 2014. The *ERO Enterprise Strategic Plan 2014-2017* includes ERO Enterprise performance metrics that will be initially used in 2014. These metrics are intended as indicators of the overall effectiveness of the ERO Enterprise in achieving its mission and the goals and objectives outlined in the *ERO Enterprise*

		Strategic Plan 2014-2017. There are four overarching metrics focused on overall effectiveness in addressing BPS risks and improving reliability. In addition, there are a number of supporting measures that assess the effectiveness of the key operational elements of the ERO Enterprise. The Caseload Index and the Mitigation Activity Aging are included in these supporting measures. NERC reports the results of these metrics on an ERO Enterprise-wide basis, and also, as applicable, distinguishes results for NERC and individual Regional Entities.
215	NERC must provide training to Regional Entities and disseminate to each Regional Entity information and direction resulting from its review of proposed violations and penalties from all eight Regional Entities.	NERC conducts separate workshops for Regional Entity staff and industry members. The workshops are offered in February and September of each year. The workshop includes instructions and practical examples and exercises on compliance and enforcement issues including risk assessments under various Find, Fix, Track and Report (FFT), Spreadsheet Notice of Penalty, and Notice of Penalty scenarios. On August 29, 2013, NERC provided training to industry and Regional Entities on finding and analyzing available public NERC enforcement data in order to identify pertinent reliability issues and trends. The training described the raw and analyzed data available on the NERC website. It also showed where NERC's compliance and enforcement trends documents, annual reports and directives could be found. NERC provides feedback and training to the Regional Entities on a monthly basis during its review of the proposed violations and penalties. This ongoing process allows NERC

		and the Regional Entities to target specific issues applicable to each specific Regional Entity. NERC disseminates to each Regional Entity information and directions on pressing compliance and enforcement matters. For example, in 2013, NERC provided guidance on the FFT process twice. The first guidance document was disseminated in March and explained how to address risk in FFT situations. The document included an updated template and requirements for FFT filings. The second guidance was issued in July, following the Commission's order approving NERC's proposed enhancements to the FFT process. The guidance included a detailed description of the updated FFT process and associated FFT templates. Furthermore, NERC conducts periodic spot checks on various aspects of the Regional Entities' processes and outcomes. For example, NERC conducted a spot check of letters of dismissals from the eight Regional Entities and disseminated issues identified during the spot check, and the potential areas of improvement. NERC developed standardized templates for letters of dismissals and distributed them to the Regional Entities along with its findings. NERC has also scheduled spot checks of mitigation plans and settlements agreements issued by the Regional Entities and will distribute appropriate guidelines based on its findings.
216	Support the suggestions of the Regional Entities for the NERC Board of Trustees Compliance Committee to increase communications with Regional Entities regarding its decisions.	NERC has increased communications with the Regional Entities by providing various forums and channels for communication.

		NERC disseminates compliance information and guidance to the eight Regional Entities mainly through the Enforcement Functional Group (EFG) and the Compliance Monitoring Process Working Group (CMPWG), both of which include representatives from each Regional Entity. The groups meet regularly to discuss compliance issues with NERC, and receive written guidance directives, as appropriate. Furthermore, NERC Enforcement staff is available to answer questions and respond to inquiries from the Regional Entities. For example, in addition to the written guidance on the enhanced FFT process, staff has provided the Regional Entities with additional guidance and assistance throughout the new FFT implementation process. *See also* Attachment 3, pages 66-69.
217	Directs NERC to report on the timeline and plan for development of a non-public central compliance data hub, including details regarding how it will operate, what information it will contain, and whether it will supplant existing processes for providing non-public data to the Commission.	The Regional Entities have implemented compliance data systems to collect and track violation data. These systems interface with NERC's centralized database. At the Regional Entity level, these systems have enabled substantial enforcement processing efficiencies. At the NERC level, these systems have enhanced NERC's ability to identify compliance and enforcement trends and compile accurate metrics. *See* Attachment 3, page 69.

Attachment 5: Status of Areas for Improvement Identified in the Order on the Three-Year ERO Performance Assessment

218-219	Provides that if NERC still wants to pursue a "warning ticket" mechanism, it must explain how the mechanism would work without running afoul of the concerns raised. NERC is free to provide that explanation in the informational filing or, if it chooses to take additional time to develop the mechanism, in a later filing.	NERC has not pursued a "warning ticket" mechanism. FFTs, for example, are remediated issues, are recorded, and can be used in a subsequent penalty matter. *See generally* Attachment 3, pages 66-69.
134	NERC should continue to encourage, and develop incentives for, registered entities to self-report potential violations to the Regional Entities.	Whether or not the registered entity self-reported is a factor considered under the NERC *Sanction Guidelines*. *See* Section 3.3.3 of the *Sanction Guidelines*, Appendix 4B to the NERC Rules of Procedure; and *Overview of NERC Activities and Accomplishments in the Five-Year Period*, pages 50-51, 55-56. *See* also Attachment 1, page 29.

FEDERAL ENERGY REGULATORY COMMISSION
DOCKET NO. RR14-___

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

ATTACHMENT 6

TO

FIVE-YEAR ELECTRIC RELIABILITY ORGANIZATION PERFORMANCE ASSESSMENT REPORT

NERC'S PLAN AND INITIATIVE FOR IMPROVING COORDINATED OPERATIONS ACROSS THE ERO ENTERPRISE

JULY 21, 2014

Improving Coordinated Operations Across The Electric Reliability Organization (ERO) Enterprise

February 2014

Purpose

The purpose of this paper is to describe a vision and path forward to achieving a highly effective and efficient Electric Reliability Organization (ERO) Enterprise. The North American Electric Reliability Corporation (NERC) and eight associated Regional Entities[1] comprise the ERO Enterprise[2]. Part I provides background on why the ERO Enterprise was created in its current form, the unique aspects of the regulatory and delegation models applied, the relationship with the regulated industry and governance, benefits and successes of the ERO Enterprise approach thus far, and remaining opportunities.

Part II lays out a vision for a successful end state, and identifies changes needed to get there, including:

- Refining roles and responsibilities
- Coordinating strategic planning
- Coordinating operational decision-making
- Achieving consistency
- Sharing tools and infrastructure for delegated functions
- Coordinating communications

PART I – BACKGROUND

Creation of the ERO Enterprise

The mission of the ERO Enterprise is to ensure the reliability of the bulk power system in North America, including the continental United States and Canada, and the northern portion of Baja California, Mexico. Entities under the jurisdiction of the ERO Enterprise are the approximately 1,900 registered users, owners, and operators of the North American bulk power system – a system that serves the needs of over 334 million people, includes installed electricity production capacity of approximately 1,200 gigawatts, and operates 211,000 miles of high voltage transmission.

In the face of increasing competition and industry restructuring, and in the context of the August 2003 Northeast Blackout, the U.S. Congress added §215 to the Federal Power Act as part of the Energy Policy Act of 2005 to create the regime of mandatory reliability standards, to be developed and enforced in the U.S. by an Electric Reliability Organization (ERO) certified by, and operating under the oversight of, the Federal Energy Regulatory Commission. NERC was certified as the ERO in July 2006 and thereafter delegation agreements were established with the eight Regional Entities.

[1] The Regional Entities are: Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), Reliability First Corporation (RFC), SERC Reliability Corporation (SERC), Southwest Power Pool Regional Entity (SPP RE), Texas Reliability Entity (TRE), and Western Electricity Coordinating Council (WECC).

[2] As used here, "ERO Enterprise" refers to the informal affiliation of NERC and the eight Regional Entities for the purpose of coordinating goals, objectives, metrics, methods and practices across statutory activities. The ERO Enterprise does not supplant obligations of each organization through statutes, regulations, and delegation agreements, but rather enhances coordination through collaborative decision-making and communications.

Equivalent relationships have been sought and for the most part realized in Canada and Mexico. Prior to adoption of §215 in the U.S., the provinces of Ontario (in 2002) and New Brunswick (in 2004) adopted all reliability standards that were approved by the NERC Board as mandatory and enforceable within their respective jurisdictions through market rules. NERC presently has legislation in place or memoranda of understanding with governmental authorities in Ontario, New Brunswick, Nova Scotia, Québec, Manitoba, Saskatchewan, and Alberta, and with the National Energy Board of Canada[3].

Regulatory Model

When enacting legal authority for mandatory and enforceable reliability standards, Congress chose the model of audited self-regulation[4], as reflected in the consensus legislative discussions. Audited self-regulation means congressional or agency (in this case FERC) delegation of power to a private organization to implement or enforce laws or agency regulations with respect to the regulated entities, with powers of independent action and review retained by the delegating agency. The advantage of the audited self-regulatory model is that the statute and agency rules are supplemented and enforced by those entities most directly involved in the regulated activity, which may provide more detailed knowledge of the operational or technical aspects of the regulated activities.

[3] NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. The provincial law now provides for mandatory compliance and enforcement with Reliability Standards. Manitoba has adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and the Northeast Power Coordinating Council (NPCC) have been recognized as standards setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. NERC standards are now mandatory in British Columbia and Nova Scotia.

[4] U.S. Code of Federal Regulations, Title 1, Chapter III, Part 305.94-1: "Audited self-regulation is defined as congressional or agency delegation of power to a private self-regulatory organization to implement and enforce laws or agency regulations with respect to the regulated entities, with powers of independent action and review retained by the agency. This self-regulatory organization is often an association of regulated entities formed for the explicit purpose of self-regulation. Audited self-regulation is an alternative for Congress to consider in legislating any regulatory program. Properly implemented and monitored, a program of audited self-regulation may effectively advance the statutory objectives consistent with the public interest and the interests of the regulated entities. In certain circumstances, this approach may result in better regulation because the agency's statute and rules are supplemented and enforced by those entities directly involved in the regulated activity, which may have more detailed knowledge of the operational or technical aspects of that activity. The regulatory program also may be more effective because it can be tailored to the individual industry or group. In addition, the agency's regulatory enforcement costs may be reduced by this approach, although such cost reductions should be considered only if they can be achieved without eroding the effectiveness of enforcement. On the other hand, audited self-regulation may present the significant risks of uneven enforcement, capture of the regulators by the regulated industry, and creating barriers to entry or competition. Where the potential for institutional self-interest is too great, self-regulation is undesirable. Other risks can be lessened by requiring the self-regulatory organization to establish and follow procedures similar to those that would be applicable if the self-regulatory organization were an agency. For these procedures to work, effective interest groups must exist, and must have access to the agency, to raise concerns about the conduct of the self-regulatory organization. And of course, the agency itself must vigilantly oversee the activities of the self-regulatory organization and of the regulated entities themselves."

Improving Coordinated Operations Across The Electric Reliability Organization (ERO) Enterprise

February 2014

As the international, multi-jurisdictional ERO, NERC is authorized to:

- Propose, monitor compliance with, and enforce mandatory reliability standards for the North American bulk power system, subject to regulatory oversight and approvals of FERC in the U.S. and applicable authorities in Canada;
- Conduct near-term and long-term assessments of the reliability and future adequacy of the North American bulk power system;
- Certify bulk power system operators as having and maintaining the necessary knowledge and skills to perform their reliability responsibilities;
- Maintain situational awareness of events and conditions that may threaten the reliability of the bulk power system;
- Coordinate efforts to improve physical and cyber security for the bulk power system of North America;
- Conduct detailed analyses and investigations of system disturbances and unusual events to determine root causes, uncover lessons learned, and issue relevant findings as advisories, recommendations, and essential actions to the industry; and
- Based on lessons learned identify the potential need for new or modified reliability standards, improved compliance, or other initiatives.

In executing its responsibilities, NERC delegates certain authorities to eight organizations, the Regional Entities. Under NERC's oversight, the Regional Entities perform certain aspects of the ERO functions through delegation agreements, which are approved by FERC in the U.S. The delegation agreements with each Regional Entity address, among other things: (i) development of regional reliability standards, (ii) monitoring compliance with and enforcing mandatory reliability standards (both North American wide and regional), certification of registered entities, registration of owners, operators and users of the BPS, (iii) reliability assessment and performance analysis, (iv) training and education, (v) event analysis and reliability improvement and (vi) situation awareness and infrastructure security.

The current regional delegation model was first adopted in 2006, with a January 1, 2007 effective date for the initial delegation agreements between NERC and the Regional Entities. It was at this time that NERC began approving regional business plans and budgets, and funding the statutory activities of the Regional Entities through revenues collected from Load-Serving Entities. NERC's oversight role and the obligations of the regions are addressed in NERC Rules of Procedure and the delegation agreements.

As shown in Figure 1, the international ERO footprint covers North America and is comprised of eight reliability regions.

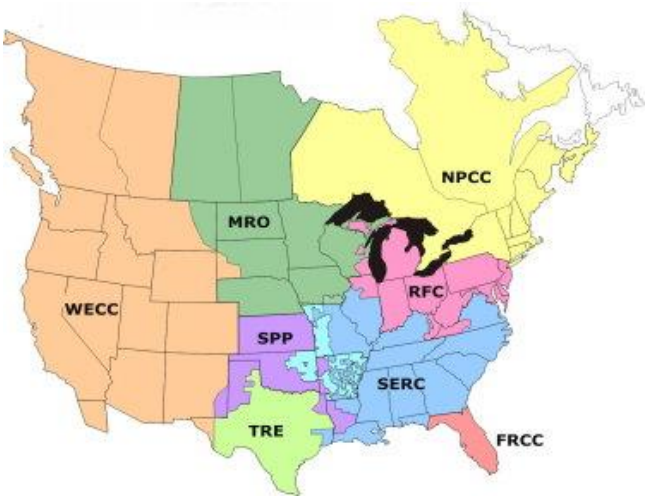


Figure 1 – Map of Regional Entities within NERC

The audited self-regulation model adopted by Congress and the further delegation of statutory functions to Regional Entities present some important benefits and opportunities, but also some challenges. Audited self-regulation results in better regulation because, "[t]he agency's statute and rules are supplemented and enforced by those entities directly involved in the regulated activity, which may have more detailed knowledge of the operational or technical aspects of that activity."[5] This has been the experience with NERC and the Regional Entities since the inception of the ERO in 2006.

The ERO Enterprise is able to directly engage and leverage local and regional technical expertise regarding reliability matters, drafting and commenting on reliability standards, reviewing system events and determining lessons learned, assessing reliability performance and future reliability impacts of emerging issues, just to name a few activities. There exist complex risks, with numerous interdependencies at both the regional and international level, and the regional structure allows us to leverage the expertise across this entire footprint. The regional structure brings greater input from industry experts than could be accommodated in a single ERO organization, and encourages senior utility executive involvement on Regional Entity boards. Experts participate in regional technical committees, providing local and regional system knowledge and experience essential in maintaining a strong technical understanding of the reliability of the interconnected bulk power system. Industry engagement in NERC and the Regional Entities builds commitment, or buy-in, from industry in successful reliability outcomes. The current model can foster reliability excellence whereas a traditional top down regulatory model would tend to enforce reliability adequacy.

Bulk power system risks are dispersed, interdependent and can be asymmetrical across North America. Combining centralized and regional activities is well-suited to identifying and addressing these risks. Given the highly technical and intricate complexities of planning and operating the bulk power system – and given that an interconnected system is a "system of systems" - the concept of local, regional and wide-area views

[5] U.S. Code of Federal Regulations, Title 1, Chapter III, Part 305.94-1

on risk is necessary and has been long accepted.[6] It follows that a "top-down" view of interconnected system risks and a "bottom-up" view of individual system risks is most effective at triangulating the priority risks to be addressed at both a local and interconnection-wide level.

With active engagement of industry experts in the ERO Enterprise technical committees and activities, it is important to maintain effective governance to ensure entities that are regulated do not unduly influence the determination and/or conclusions of the ERO Enterprise. Balance is achieved through governance controls including, but not limited to: an independent board at NERC and segregation of responsibilities and decision-making, especially on compliance and enforcement matters; governance measures at the regions, such as legal and operational separation from registered entities and in some regions the inclusion of independent directors; and, maintaining compliance and enforcement matters as confidential and separate from direct stakeholder participation. Independence and objectivity of NERC and the Regional Entities are further enhanced by government authority oversight, including periodic audits. This layered delegation approach – government to NERC, and NERC to Regional Entities – allows much more active participation by industry participants at the regional level, while maintaining independent oversight by NERC and applicable government agencies.

The distributed governance structure of the ERO Enterprise, with NERC and each Regional Entity having its own board, understandably presents challenges in coordinating ERO Enterprise activities and priorities. At the same time, this distributed governance provides an opportunity to create reliance and trust of the overall enterprise through greater transparency and accountability among all nine entities – the nine entities are mutually interdependent and must be transparently accountable to each other and their respective stakeholders to ensure overall success.

It is also significant that the North American bulk power system is an interconnected, international grid. A single integrated forum – the ERO Enterprise working at the North American and regional levels – ensures that the interests of multiple governmental jurisdictions and their stakeholders can be considered and addressed. Outcomes that are mutually satisfactory across all of North America can then be taken by NERC to the applicable regulatory authorities for approval, without concerns over intrusions by governmental agencies in one country over another country's sovereignty.

ERO Enterprise Progress and Accomplishments Through 2013

The ERO Enterprise has been effective in mitigating a number of important risks to the reliability of the bulk power system since 2006. Results do matter and the achievements since 2006 support the notion that the delegation model works. Using the ground-up approach, the ERO Enterprise has taken advantage of the ability of the Regional Entities to uncover trends and leading indicators of potential reliability problems, such as protection system misoperations and transmission facility right-of-way clearances. The ERO Enterprise was able to use this information to craft strategies to prevent these potential risks from causing actual harm to the bulk electric system. The ERO Enterprise has developed a system of bulk power system reliability metrics based on actual measured performance of the grid. This system of metrics is driven by analysis of event reports, transmission and generator outage data, and relay misoperations. The most recent annual *State of Reliability 2013* report indicates the bulk power system remains reliable and that certain risks have been reduced. Excluding weather-related events, the number of significant system events

[6] For example, over forty years ago, regional reliability organizations were formed; over fifteen years ago, regional reliability coordinators were formed.

resulting in loss of firm load decreased from nine per year on average from 2008 to 2011 down to two events in 2012, and a similar trend is continued through 2013.

Transmission outages caused by grow-in of vegetation, a major cause of the 2003 and several preceding large blackouts, have been virtually eliminated in recent years. NERC introduced a new mandatory standard in 2007 requiring transmission owners to implement vegetation management programs to maintain safe clearances. Strong enforcement actions by NERC and Regional Entities were effective in eliminating grow-ins and reducing the risk of cascading failures initiated from vegetation contacts as seen in the past. Industry experts helped to shape the standard, including a recent update to focus on reliability performance outcomes and risk management while maintaining practicality.

Working with industry system protection experts, NERC developed new relay-loadability requirements for transmission line relays. In the August 2003 Northeast Blackout, over 300 high voltage transmission lines tripped in a high speed cascade due to a previously little understood issue with the relay settings, even though no fault conditions existed on those lines. Industry experts were able to determine that the settings could be modified to prevent a similar future cascade and the requirements were included in new reliability standards. The risk of repeating this mode of uncontrolled high speed cascade of transmission lines has been substantively mitigated.

Industry experts have worked with NERC and the Regional Entities to develop new standards for frequency response to address decades of gradual decline in resources available to respond to frequency disturbances. Experts are currently developing technical methods and tools to mitigate the risks and potential consequences of solar magnetic disturbances. Guidelines have been developed and training implemented to prevent a repeat of a February 2011 loss of generation and firm load in Texas due to extreme cold weather. These are but a few examples of how direct engagement of industry experts through the ERO Enterprise can result in reliability improvements that benefit the public.

The compliance monitoring and enforcement program implemented by NERC and the Regional Entities has been effective in ensuring that compliance violations are identified and mitigated, thereby reducing reliability risk. The ERO Enterprise processed 5,115 confirmed violations of Reliability Standards through 2012 year end. Of these, 85% were deemed to present minimal risk to bulk power system reliability, 13% presented moderate risk, and 2% high risk. The *State of Reliability 2013* report indicates that risks due to noncompliance have trended significantly lower in recent years. NERC and Regional Entities have encouraged self-reporting of violations and timely mitigation – to date, more than 70% of all violations are self-identified by registered entities.

The ERO Enterprise has implemented uniform procedures for compliance monitoring and enforcement, including penalty guidelines, and continues to focus on improving consistency of implementation. FERC has approved the vast majority of notices of penalty without comment since 2008. In recent years, the ERO Enterprise developed greater efficiencies in processing enforcement issues through the find, fix and track (FFT) and spreadsheet notice of penalty (SNOP) initiatives. Work is now continuing to develop the Reliability Assurance Initiative (RAI) to ensure risks are effectively and efficiently addressed through the compliance monitoring and enforcement programs. RAI specifically seeks to improve the reliability of the BPS due to enhanced focus on high reliability risks and registered entities' internal controls relative to those risks, performance of self-assessments and corrective actions, and enhancement of the enforcement processes to process violations in accordance with risk.

The ERO Enterprise has implemented registration criteria to identify entities that can have an impact on bulk power system reliability. There are approximately 1,900 entities registered and an even greater number of entities engaged in reliability activities through the ERO Enterprise. Industry engagement is significantly greater than the number of entities that historically were engaged in NERC during the voluntary era.

The ERO Enterprise has developed a systematic approach to capturing and analyzing bulk power system events. Industry has been very responsive to a program established in 2011 for the voluntary reporting of system events, including sequence of events, root causes, and mitigating actions. Though voluntary, the ERO Enterprise is experiencing nearly 100% participation by industry. The information arising from this program is valuable in identifying reliability risks and trends and in developing lessons learned and mitigating actions for industry.

Since the initiation of the ERO model, major progress has been made in securing critical infrastructure in the bulk power system. Mandatory cyber security standards have been established, and the ERO Enterprise has actively monitored compliance with these standards, noting significant numbers of compliance gaps mitigated by registered entities.

Finally, NERC and the Regional Entities have developed electronic tools, forms, and templates to support information management across the ERO Enterprise, and NERC and Regional Entities are looking to standardize these tools to drive more efficiencies

The outcomes outlined above are a sampling of the positive results that have been developed within the current ERO Enterprise framework, demonstrating that the ERO Enterprise model based on the principles of audited self-regulation and delegation to Regional Entities can be and has been effective in improving reliability and serving the public interest.

PART II – VISION FOR A SUCCESSFUL END STATE

A Vision for the ERO Enterprise

Despite the successes outlined above, the current nine-entity model is not without challenges and risks. The formative years, identified as 2006 through 2013, were focused mainly on achieving the substantial work at hand, guided by the rules of procedure, delegation agreements, and extensive amounts of coordination of activities. With the experience gained and the maturation of the ERO Enterprise, however, it is clear that substantial benefits can be envisioned for an end state.

At its core, the ERO Enterprise must exercise effective and well-coordinated reliability oversight that mitigates reliability risks to the bulk power system. The ERO Enterprise programs must be effective at the mission of ensuring risks are addressed to maintain reliable operations of the bulk power system.

The end state should include more clarity around the roles and responsibilities between NERC and the Regional Entities which will lead to better coordination of goals, more uniform work processes/tools, and performance measures across the enterprise, along with an understanding that all parties comprising the ERO Enterprise must be vested in each other's success. These improvements will create a framework for higher levels of productivity, less duplication, and greater efficiency through more standardization.

The ERO Enterprise must adhere to certain principles. The ERO Enterprise must:

- Apply technical expertise that is focused on risks to the bulk power system and important reliability outcomes;
- Achieve results and methods across the enterprise that are predictable, consistent and timely;
- Share common goals, objectives and measures of success;
- Build relationships that are founded on candor and mutual trust, openness and cooperation;
- Apply collaborative decision-making;
- Ensure efficiencies, minimize duplication and any activities not affecting reliability outcomes;
- Avoid undue burden, discrimination, or capriciousness affecting regulated entities.

The remainder of this paper identifies a path forward to achieving excellence in the oversight and execution of statutory functions and mitigation of bulk power system reliability risks. This discussion is organized in the following areas:

- Clarifying and refining roles and responsibilities
- Coordinating strategic planning
- Coordinating operational decision-making
- Achieving consistency
- Sharing tools and infrastructure for delegated functions
- Coordinating communications

Each section describes the key goals that must be achieved to implement the ERO Enterprise vision for effective, coordinated operations across the enterprise.

Clarifying and Refining Roles and Responsibilities

Achieving the vision requires a clear understanding of the roles and responsibilities of both NERC and the Regional Entities and a clear set of expectations in the execution of the activities performed across the ERO Enterprise.

As the single ERO certified in the U.S. and sanctioned in Canada, NERC has unique responsibilities within the nine-entity ERO Enterprise. NERC is accountable to be the program designer and architect for statutory functions, setting necessary qualifications and expectations for the performance of delegated activities. NERC should respect and be responsive to the expertise and views of Regional Entities, whose staffs have a technical understanding of regional operations, are experienced in the direct interactions with registered entities, and promote the entire ERO Enterprise as one collective thought leader in setting direction and expectations. NERC should also set expectations, provide necessary training and coaching and assess performance of delegated statutory functions.

These roles suggest different qualifications and activities for NERC staff than in the past. Rather than observing regional activities and providing feedback or reviewing and approving final results submitted to

NERC, the emphasis needs to shift toward a different set of skills involving program design and setting management controls to ensure effectiveness. Essential capabilities at NERC include identifying personnel qualifications for program implementation, which itself suggests senior and experienced qualifications, and being able to determine when program adjustments are needed to address bulk power system risks or program risks.

All of this suggests NERC should design its oversight of program areas to encompass program design and development, operational oversight and leadership, coaching and support, and ongoing assessment with feedback to the corresponding regional programs. The goal is to add value and ensure the successful performance of the enterprise. The NERC program staffs must be experts in their field and competent program designers and managers, and teachers and coaches for the regional program staffs. The NERC staff needs to be able to recognize risks, to guide the program and introduce necessary adjustments along the way.

Furthermore, given the distributed and regional nature of the risks being managed and the external environment of a diverse industry across North America, this leadership role must be conducted in a consultative fashion. While NERC has overall responsibility for program design, the goal is to leverage the expertise across the ERO Enterprise in developing future program enhancements. Once designed, the program must be implemented by all Regional Entities consistently in accordance with the approved design. Any variations that do exist must be planned and coordinated for the overall betterment of the ERO Enterprise, within existing fiduciary responsibilities.

NERC is positioned to review data and information from all of the Regional Entities to identify trends and leading indicators of potential reliability risks, develop responsive strategies, and communicate this information to all of the Regional Entities to ensure a uniform, consistent manner of implementation. As the ERO Enterprise matures, process controls should be well established and routinely monitored, allowing greater emphasis on identifying and addressing threats and risks to reliability of the bulk power system.

Implementation of the oversight role must include well-defined and transparent procedures and controls so that all parties understand the qualifications and expectations surrounding execution of delegated functions and how results will be measured. Just as the delegated activities should apply consistent methods, practices, procedures, and tools, the oversight layer should also not be ad hoc, arbitrary, or opaque. It must be known and documented in advance, complete with reporting requirements and performance measures. NERC should be providing ongoing feedback to Regional Entities on patterns and trends, affecting both bulk power system risks and enterprise risks.

ERO Enterprise program oversight should include the following ***essential oversight elements*** to be provided by NERC in consultation with Regional Entities:

- An overall program design indicating the program purpose and goals, and design of controls to manage risks;
- Documentation of common methods, practices and procedures to be applied in the program and performance expectations for each;
- Statements of necessary qualifications of key positions within the regions for conducting certain statutory activities (*e.g.*, for auditors and investigators), and identification of any standards for critical positions;

- Training of NERC and Regional Entity staff for select positions in the conduct of delegated functions;
- A documented and transparent set of process controls and measures to assure delegated responsibilities are properly completed, and to assess the effectiveness of the delegated activities in assess effectiveness of delegated activities in managing bulk power system and enterprise risk; and
- Periodic reporting of results and feedback to Regional Entities on trends and providing opportunities to enhance consistency and effectiveness of results.

The objective is to integrate these elements into the ERO Enterprise operating model on a consistent basis across all the program areas. This is also an area where NERC executive management needs further work on a best design for managing functional area relationships with the regions.

The success of the ERO Enterprise requires NERC and the Regional Entities to recognize that each delegated activity is part of a single overall ERO Enterprise program, such as compliance assurance, enforcement, reliability assessment, or event analysis.

While NERC is responsible for the program design, the Regional Entities are responsible for providing insight and input into the overall design and development of each program area. In support of this, NERC should ensure there are mechanisms for the Regional Entities to provide meaningful insight and direction for incorporation into program design. Regional Entities should adopt conforming methods, practices, and procedures identified in the program design, with exceptions limited to those areas identified in coordinated plans for the purpose of promoting innovation or addressing material regional variations. Regional Entities need to report results using the tools provided, and consistent with reporting requirements identified in the program. Regional Entities should be receptive to feedback from NERC and making responsive adjustments. Regional Entities should ensure staffs are provided the training and development necessary to meet the qualifications required to implement the ERO Enterprise programs.

Regional Entity and NERC staff have an obligation to meet the highest ethical and professional standards in conducting ERO Enterprise work, including independence, objectivity, and providing the best available expertise for addressing bulk power system risks. Regional Entity staff should operate as part of the broader ERO Enterprise and communicate solidarity with the overall enterprise-wide program objectives, methods, and practices.

The ERO Enterprise is aimed at achieving the following goals:

<u>Action item 1</u> – NERC includes in its review of Regional Entity business plans adequacy of resources and alignment of the plans for achieving delegated function objectives and outcomes described in the three-year plan.

<u>Action item 2</u> – NERC, in collaboration with Regional Entities:

- ***a) develops a comprehensive overarching design and set of controls, reporting requirements, and feedback mechanisms for each delegated statutory function, including the essential oversight elements listed above;***
- ***b) reevaluates its organizational structure and leadership qualifications necessary to provide effective design and oversight of statutory activities;***

c) identifies functional qualifications for select delegated activities, such as auditors and investigators; and,

d) adopts risk-based approaches to monitoring performance of delegated functions and providing effective feedback and coaching to continuously improve overall ERO Enterprise performance;

Action item 3 – Regional Entities:

a) work in a coordinated fashion to support NERC in the development of comprehensive functional program designs and controls;

b) adapt existing regional programs for delegated functions to conform with emerging program designs provided by NERC; and

c) ensure Regional Entity staffs meet qualification and training requirements.

To improve the delegation process, NERC and the Regional Entities should work together to update and refine the delegation agreements, which are due for renewal in May 2015, to provide a clearer division of responsibilities, both related to the division of performance of statutory functions and oversight of those functions, and to provide effective mechanisms to resolve routine differences.

Coordinated Strategic and Business Planning

There has been significant progress, achieved through collaboration among senior executives of NERC and the regions, in developing a shared, rolling three-year strategic plan for the ERO Enterprise. Adoption of the ERO Enterprise goals and objectives into business plans across all of the regions has been varied and incomplete. Common performance measures are just emerging and have not yet been adopted into performance management systems across the ERO Enterprise.

The end state for enabling excellence in the execution of statutory reliability activities is that NERC and the eight Regional Entities must work from a common strategic plan, with success measured by a shared set of performance metrics. A common strategic plan and measures does not suggest performing every activity in lock step, but every activity must be coordinated across the enterprise and must be performed consistently. For example, several regions have been working on pilot programs to develop and demonstrate RAI methods as well as the transition to the CIP Version 5 standards.

Action item 4 – NERC and Regional Entities develop and maintain a joint three-year strategic plan for the ERO Enterprise describing the goals and deliverables for statutory functions and this plan should guide the development of each Regional Entity's annual business plans. Additional goals and deliverables that are complimentary or supplemental to the strategic plan may be developed at the Regional Entity level.

Action item 5 – NERC and Regional Entities develop and transparently report results based on a common set of performance measures focused on bulk power system reliability outcomes and effectiveness of the statutory programs. These measures are considered in the performance management program at each entity.

Coordinated Operational Decision-Making

The current model allows and depends on successful delegation of activities. Although statutory functions are delegated, there remains substantial need to coordinate operational decisions that arise in the execution of these duties.

Improving Coordinated Operations Across The Electric Reliability Organization (ERO) Enterprise

February 2014

NERC and the Regional Entities have institutionalized a number of mechanisms to coordinate operational decisions across the enterprise. Note that this discussion and the ensuing recommendations focus on operational decisions that need to be made regarding implementation of statutory functions across the ERO Enterprise and is not intended to reach into the internal management decisions of each organization.

For policy and directional decisions, NERC and Regional Entity CEOs have been meeting periodically for most of the lifetime of the ERO Enterprise although more sporadically in the beginning. In the most recent two years, coordination meetings have been at least monthly, including 6-8 face to face meetings annually. There is an agreed upon protocol for reaching consensus decisions. Although this process has seen partial success, it is still a work in progress. The group is still working on issues such as what level of decisions should be brought to the CEO group for consensus decisions.

In addition to senior leadership coordination, there are approximately two dozen working groups collaborating across various functional areas of the ERO Enterprise. There are groups coordinating compliance monitoring and audits, enforcement, legal, finance, registration, and reliability assessments, just to name a few. Generally these groups are effective in working out common templates for information sharing and resolving common practices and methods at the working level. As with the senior leadership group, most of these groups have achieved good results and are effective in coordinating practices, methods and formats, but there remain opportunities for improvement. One challenge is shifting these working groups from being mainly self-directed problem solvers to being more focused on the strategic plan objectives and having accountability to the CEO leadership team. Also there are concerns that need to be addressed regarding the magnitude of the staff resource commitments stemming from these coordinating activities.

The preferred approach is to proactively establish a more collaborative model and recognize that regional staffs for most functions typically have valuable first-hand experience in implementing the activities on the front lines with registered entities. However, success depends on collaboration that results in timely and effective decisions that all entities in the enterprise agree to implement, and the avoidance of unilateral decision-making that steers portions of the ERO Enterprise off into alternative methods and practices for delegated functions.

<u>Action item 6</u> – ERO Enterprise senior leadership (ERO-Executive Management Group or "ERO-EMG") continues maturing the collaborative decision-making process and setting the direction and policy for the enterprise as well as driving this collaboration throughout the ERO Enterprise organizations.

<u>Action item 7</u> – All nine ERO entities abide by the joint enterprise decisions of the ERO-EMG, and the NERC CEO should make final determinations if consensus is otherwise not achievable for an action that is required.

Achieving Consistency

Consistency of methods, practices, procedures, and tools has been a challenge since the onset of the ERO Enterprise. Consistency is defined by the ERO Enterprise as the use of common methods, practices and tools. The principle initial challenge was that the majority of processes were new and NERC did not foresee the importance of developing common processes and procedures in effective oversight. Instead NERC relied on the Rules of Procedure and the Delegation Agreement to deliver a basic level of consistency which has failed to meet the expectations of industry. Therefore, given the lack of common processes and procedures from NERC, Regional Entities developed their own methods, practices, procedures and tools. While there has been significant progress in working out substantive differences through the leadership and working group processes described previously, there also remain significant variations in methods, practices, procedures, and tools across all nine entities. Today, the biggest challenge in addressing consistency is gaining common agreement on processes and procedures with the backdrop of years of institutionalized differences among NERC and the Regions. Over the past few years there has been significant work toward converging disparate practices across the enterprise. The recent RAI activity, for example, has resulted in some convergence of methods and practices in compliance. In 2013, joint projects saw the completion of a common auditor checklist and an auditor handbook.. A common business process has been developed for managing exceptions to the Bulk Electric System definition. Regions are implementing a common event analysis program and root cause analysis tools.

Some convergence has also been initiated through the use of common electronic tools. Early in the formative years of the ERO Enterprise some of the regions began to deploy common portals to manage compliance information. While these tools helped drive more consistent reporting of results from the regions, even today all nine entities are not using the same information management tools. Tools and infrastructure are covered in more detail in the next section.

Therefore, progress has been made but if common methods, practices, procedures and tools are the yardstick, the enterprise remains very immature. The ultimate success of the ERO Enterprise depends on there being one compliance program, one enforcement program, one event analysis program, etc. Regulated entities will have greater confidence and trust in the ERO Enterprise if they believe their regulatory oversight is not subject to arbitrary variations and possible discrimination from one region to the next. Outcomes will be more predictable and consistent if each statutory function is operated in a unified fashion across the ERO Enterprise. Outcomes will also be more readily measurable to demonstrate the reliability impacts and benefits of the enterprise programs. In the long term, getting past the transition from legacy approaches, there will be significant efficiencies. Such a transition requires the development of a core set of common methods, practices, procedures, and tools, which are principally the responsibility of NERC to produce, but in collaboration with Regional Entities.

Achieving consistency in the end state does not necessarily require identical internal procedures at each Regional Entity, although efficiency would dictate there should be more commonality than exists today. Consistency does not require that each Regional Entity produce identical outcomes given a particular set of circumstances. However, consistency does mean that the approach, methods and practices are the same across the ERO Enterprise and that outcomes produced from the application of local and regional expertise and judgment of the Regional Entity staff are fair, reasonable, and without bias. The goal is consistent methods, practices, procedures and tools that deliver fair and reasonable outcomes.

While consistency is desired, the ERO Enterprise must flexible to permit progress through innovation. Therefore, some variations may be necessary in the interest of progress. However, Regional Entity and NERC leadership need to be prepared to adapt to new approaches, methods, and practices. Some regional variations can actually have value, when implemented on a planned and coordinated basis. Differences for the purpose of testing new approaches, such as during the current RAI pilots and CIP Version 5 pilots, can be helpful in advancing innovation and experimenting with alternative methods. There may also be appropriate variations due to regional differences. An example would be the unique framework in Texas for involving the utility commission in review of enforcement actions. The drive to consistent methods, practices, procedures and tools should not inhibit innovation and the emergence of continuous learning and adaptation. However, managing the balance between consistent approaches and regional differences driven by necessity or creative adaptation should not succumb to the tendency to hold tightly to legacy methods. This shift must remain under the close scrutiny of the ERO-EMG, with accountability for progress to the respective boards, and all entities must be prepared to adopt changes to drive to more consistent methods, practices, procedures, and tools.

Action item 8 – With NERC leading, the ERO Enterprise develops a core set of methods, practices, procedures, and tools to support unified implementation of the major statutory functions of NERC. In doing so, the ERO Enterprise commits to put the best talent available throughout the collective organizations to achieve this goal.

Sharing Tools and Infrastructure for Delegated Functions

As previously described, the infrastructure and electronic tools used by NERC and the eight Regional Entities to implement delegated functions began the ERO era as nine islands. In 2008, the Regional Entities started collaborating on the sharing of portals in an effort to converge onto best practices and provide efficiencies. From this effort emerged two primary platforms for the management of information to support delegated functions. There are two systems which support regional CMEP work:

- OATI webCDMS. The Compliance Data Management System (CDMS) was internally developed by MRO and SPP during the voluntary compliance era of standards. The system was transferred to OATI, a Minneapolis-based software company, in 2008 and became webCDMS. The OATI webCDMS is used by MRO, RFC, WECC, TRE and SPP.
- Guidance. A portal system initially developed by SERC through Guidance a software company in Southern California. SERC, FRCC, and NPCC use the Guidance system.

These early implements were principally focused on compliance information management.

Beginning in 2009, NERC became engaged and built the Compliance Reporting and Tracking System (CRATS) as a further development of the Guidance portal solution. An interface was built to allow data from the CDMS solution to flow into CRATS. Since this time a majority of the regions use the CDMS solution, further emphasizing the importance of this data interface. For several years the flow of compliance information was subject to breakdowns and was very labor intensive for NERC and regional staffs to find the disconnects blocking the consistent flow of compliance information. In late 2012 and 2013 NERC contracted with OATI to manage the CRATS system and staffs across the enterprise were able to resolve the vast majority of information disconnects so that the compliance information flow today is reasonably satisfactory and consistent, albeit built on a patchwork underlying system.

During this evolution, each entity of the enterprise developed other tools as needed to implement activities. For example, NERC developed a tool for maintaining records of the standards registered ballot body and for the conduct of ballots on reliability standards. There are portals at NERC and some of the regions for issuing alerts and tracking recommendations. For the most part, these various applications were developed in isolation from other applications, using various contractors or using in-house resources. Many of these applications are running to the end of their lives and becoming increasingly difficult to maintain at an expected level of functionality.

In 2011 a shift started to take place from the top. The senior leadership across the ERO Enterprise began to articulate a common vision in support of unifying and modernizing the infrastructure and applications needed to support NERC statutory functions. Arriving at an integrated set of applications for management of information in each of the principle delegation areas would enable the enterprise to leverage future efficiencies and eliminate manual data manipulation and validation that is prevalent in the existing tools. Integrated applications across the enterprise would also lead to greater consistency and trust in the NERC processes, and registered entities would see a more seamless interface on which to manage all of its interactions with the ERO Enterprise. Another benefit, lacking today, would be the sharing of information across functional activities, such as information from event analysis and compliance providing useful feedback to standards development.

As part of this shift, NERC hired a contractor in 2011 to conduct a comprehensive study of the ERO Enterprise functional processes and needs. The final report at the end of 2011 led to the formation of an ERO Enterprise Project Management Organization (PMO) that was staffed by NERC but focused on enterprise-wide applications and enabling infrastructure and support services. A first application, the bulk electric system (BES) exception management tool, has been developed and tested ready to handle the expected flow of industry requests in response to the new BES definition. Plans and projects are underway for enterprise-wide applications to manage reliability assessments, event analysis, and establish a common database for information sharing.

In parallel NERC is developing several applications that are uniquely tied to NERC's responsibilities, such as standards information management and balloting tools. The path forward is that, where appropriate, enterprise-wide tools are being developed by NERC through the PMO under the oversight of the ERO-EMG and NERC is developing compatible applications on the same platform for NERC-only activities.

The vision of a comprehensive set of integrated and seamless applications to support the core delegated functions of the ERO Enterprise is essential for the future success of the entire enterprise. The necessary sharing of information between Regional Entities and NERC is essential and the efficiencies and consistencies in methods and practices will be unachievable without the infrastructure to manage extraordinarily large volumes of data that need to be converted into useful information for the purpose of identifying and managing bulk power system risks. However, any enterprise-wide systems approach presents significant risk itself and requires that the projects be executed well and the resulting applications fully meet the needs of the enterprise. A usable, uniform set of tools will drive consistency and lower costs across the ERO Enterprise.

<u>Action item 9</u> - The ERO EMG develops ERO Enterprise IT Applications, where appropriate, to support common processes, to enhance the efficiency and effectiveness of Regional Entities' practices, to increase the consistency of the interface with registered entities, and to facilitate NERC's oversight function.

Coordinating External and Cross – ERO Enterprise Communications

Communications are important to the effectiveness of the ERO Enterprise. Communications can help set expectations for registered entities and stakeholders and demonstrate a common and consistent approach for regulators and the public.

Starting in May 2013, the NERC Board of Trustees initiated a practice of meeting twice yearly as a group with all of the chairs and vice chairs of the Regional Entities. A portion of the meeting is conducted with the NERC and regional CEOs present, followed by a session in-camera. This high level outreach among the nine boards holds significant promise in communicating common purpose and direction, and sharing any concerns among the boards of the ERO Enterprise. These meetings will further help to ensure the mutual accountability previously described that is essential to the successful operation of an enterprise comprised of nine distinct organizations.

A communications working group has been active for several years, coordinating consistent messaging across the ERO Enterprise, particularly with regard to media relations, incident response, and external branding.

NERC and Regional Entities have also coordinated outreach to FERC Commissioners and staff, and Canadian governments. These efforts are typically coordinated through the NERC Office of External Affairs.

The more challenging aspect of coordinating communications is around the operations of the enterprise and key initiatives, such as RAI. Although recent efforts to coordinate key messages and direction have been successful, there remain too many instances of disjointed communications across the entire spectrum of the enterprise. This creates confusion and anxiety with stakeholders and rather than gaining support for necessary initiatives, it creates concern and pushback over the uncertainty of direction.

***Action item 10** – All parties of the ERO Enterprise, including leadership and staffs, convey shared and consistent messages from the enterprise perspective and communicate together to minimize messages emphasizing self-importance or uniqueness.*

***Action item 11** – NERC and Regional Entities continue the joint board coordination to ensure oversight and accountability of all elements of the enterprise, and should continue to refine and expand coordinated outreach to government entities in the U.S. and Canada, stakeholders, and media.*

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D R A F T

2015 Business Plan and Budget

Florida Reliability Coordinating Council, Inc.

DATE: 5/16/2014 D R A F T

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Introduction

TOTAL RESOURCES (in whole dollars)	2015 Budget	U.S.	Canada	Mexico
Statutory FTEs	30.91			
Non-statutory FTEs	18.35			
Total FTEs	49.26			
Statutory Expenses	$ 7,179,844			
Non-Statutory Expenses	$ 8,422,053			
Total Expenses	$ 15,601,897			
Statutory Inc(Dec) in Fixed Assets	$ (17,611)			
Non-Statutory Inc(Dec) in Fixed Assets	$ (30,071)			
Total Inc(Dec) in Fixed Assets	$ (47,682)			
Statutory Working Capital Requirement*	**(657,395)**			
Non-Statutory Working Capital Requirement**	**122,583**			
Total Working Capital Requirement	**(534,812)**			
Total Statutory Funding Requirement	$ 6,504,838			
Total Non-Statutory Funding Requirement	$ 8,514,565			
Total Funding Requirement	$ 15,019,403			
Statutory Funding Assessments	$ 6,237,838	$ 6,237,838		
Non-Statutory Fees	$ 8,240,106	$ 8,240,106		
NEL				
NEL%				

*Refer to Table B-1 on page 42 in Section B.
**Refer to the Reserve Analysis on page 58 in Section C.

Organizational Overview

The Florida Reliability Coordinating Council (FRCC) is a Florida not-for-profit corporation that was formed in 1996 and is one of the eight regions of the North American Electric Reliability Corporation (NERC). The FRCC's mission is to ensure and enhance the reliability and adequacy of the Bulk Electric System (BES) in Florida now and into the future. The FRCC's Web site is www.frcc.com. The FRCC Region is comprised of all of Florida east of the Apalachicola River. Florida's unique geography and its highly integrated transmission system coupled with its single interface boundary to the rest of the Eastern Interconnection required the development of a reliability focus in the FRCC Region. Membership in the FRCC's Regional Entity Division is open to any entity, without cost, that has a material interest in the reliability of the BES in the FRCC Region. Currently there are 69 Registered Entities within the FRCC

Region. The FRCC is governed by a balanced stakeholder Board of Directors, and accomplishes its activities through qualified professional staff and standing committees which also have balanced stakeholder governance.

The FRCC provides the statutory functions and services for the FRCC Region through its Regional Entity Division. Non-statutory services for the FRCC Region are provided through its Member Services Division. This divisional structure is an efficient and effective means of clearly separating statutory and non-statutory activities and related funding for each. The revised FRCC Bylaws, creating this divisional structure, were first approved by the Federal Energy Regulatory Commission ("FERC") on March 21, 2008.

The FRCC Regional Entity Division works to enhance the reliability of the BES in the FRCC Region pursuant to the approved Regional Delegation Agreement with NERC, as the Electric Reliability Organization ("ERO"), under the authority of the FERC. The functions performed by the FRCC Regional Entity Division include regional reliability standards development, compliance monitoring and enforcement of reliability standards, reliability assessment and performance analysis, event analysis and reliability improvement, training and education, situation awareness and infrastructure security. The Regional Entity division of the FRCC has one standing committee, the FRCC Regional Entity Committee and Compliance Forum (RECCF). This committee provides input to the FRCC in support of the delegated activities and functions.

The Member Services division of the FRCC provides, coordinates and administers a variety of services relating to the reliable planning and operation of the BES within the FRCC Region. These services are carried out by the FRCC Planning Committee (PC) and the FRCC Operating Committee (OC) and their various subcommittees, task forces and working groups, as well as FRCC Staff.

The FRCC PC and OC actively participate in the development and approval of their committee's budget. The budgets reflect activities of each committee's responsibilities, such as reliability coordination, resource adequacy, stability studies, transmission studies, operations tools, telecommunication tools and infrastructure.

Each year, the total FRCC budget is presented to the FRCC Board of Directors early in the second quarter for informational purposes prior to final approval in June. This process gives all FRCC members advanced indication of the funding level, both statutory and non-statutory, which will be required for the coming fiscal year (January 1 – December 31). This allows for timely inclusion of each member's funding responsibility in their individual budgeting process. The final budget is presented for approval to the FRCC Board of Directors in June of each year and is then submitted to NERC for approval by the NERC Board of Trustees and then by FERC.

Membership and Governance

The FRCC's members (in both divisions) include investor-owned utilities, cooperative utilities, municipal utilities, power marketers, independent power producers and others. Membership is currently 30 FRCC members in the Regional Entity Division and 23 FRCC members in the Member Services Division including affiliate and adjunct members.

The FRCC has six (6) membership sectors which include the following:

- Non-Investor Owned Utility Wholesale
- Load Serving Entity
- Generating Load Serving Entity
- Investor Owned Utility
- Suppliers
- General

There are currently two (2) members in the General Sector of the Regional Entity Division and no members in the General Sector of the Member Services Division.

The activities of FRCC are governed by its Board of Directors. The Board is comprised of senior level executives from members of FRCC.

As part of its responsibilities, NERC, as the ERO, delegates its authority to Regional Entities to perform certain functions through delegation agreements. On October 21, 2010, FERC approved revised delegation agreements between NERC and the eight (8) Regional Entities that became effective January 1, 2011 and will expire at the end of 2015. These delegation agreements describe the responsibility and authority delegated to the Regional Entities. NERC and the Regional Entities revised the delegation agreements in 2010 to improve the efficiency, transparency, quality and effectiveness of the combined NERC and Regional Entity operations. The funding for Regional Entities is approved separately with each Regional Entity submitting its own business plan and budget for consideration by NERC and FERC.

Statutory Functional Scope

The FRCC carries out its delegated functions as outlined and detailed in Exhibits A, B, C, D and E of the delegation agreement. NERC and the Regional Entities will continue to work under the existing regulatory framework governing the establishment and enforcement of reliability standards for the BPS. The existing delegation agreements expire on January 1, 2016. NERC and the Regional Entities will work collaboratively to identify any necessary revisions to the delegation agreements as renewal efforts begin in 2014 and continue through 2015. The delegated functions as defined by the NERC Rules of Procedures include:

- Reliability Standards Development (“RSD”) - Section 300
- Compliance Monitoring and Enforcement (“CMEP”) - Section 400
- Organization Registration and Certification - Section 500 (This program budget has been combined with the Compliance Monitoring and Enforcement function budget.)
- Reliability Assessment and Performance Analysis (“RA”) - Section 800 (including necessary data gathering activities and Events Analysis)
- Training, Education and Operator Certification (“TE”) - Section 900
- Situation Awareness and Infrastructure Security (“SA”) - Section 1000

2015 Key Assumptions

The NERC and Regional Entity business plans and budgets reflect a set of common assumptions (see Exhibit A of the 2015 NERC Business Plan and Budget) developed jointly by NERC and the Regional Entities as part of the annual business plan and budget process. The significant assumptions underlying FRCC's 2015 business plan include:

- NERC will provide oversight of the Regional Entities performance of their delegated functions to ensure that the delegated responsibilities are adequately performed. The Regional Entities are expected to continue to have the primary responsibility for day-to-day operations and interactions with Registered Entities. NERC and the Regional Entities will also work to refine and revise procedures and processes to eliminate duplication, increase operational efficiencies, to enhance ERO-wide consistency and to achieve measurable reliability outcomes, consistent with their respective roles and responsibilities.
- Cost pressures may affect some stakeholder resources available to participate in NERC and Regional Entity activities. However, the assumption of continued industry participation in support of key program areas such as event analysis, reliability assessments and standards development is included in this business plan and budget. NERC and the Regional Entities will evaluate projected initiatives involving stakeholder participation to determine the availability and adequacy of industry resources to support these undertakings.
- The effective date for compliance with the CIP Version 5 standards will be April 1, 2016 for High and Medium impact assets and April 1, 2017 for Low impact assets. The transition between V3 to V5 will be a mission critical activity in 2015. The Regional Entities must plan to support the ongoing CIP v5 transition plans and should anticipate an expansion in the number of Registered Entities that require guidance during 2015. For most CIP activities, the resource demands are expected to increase throughout the planning period.
- The implementation of a BES exception process will require the allocation of resource requirements from several FRCC departments. Resources are expected to manage the process execution, technical validation of the definition and exception requests, and requests for registration and certification reviews. However, the long-term impact cannot be fully assessed at this time as the resource requirements will be based on the number and complexity of exception and registration requests received.
- NERC will continue to budget and incur costs to operate and maintain the software applications and systems known as Situational Awareness for FERC, NERC, and Regional Entities ("SAFNR"). Additional resource investments may be required to enhance the capabilities of SAFNR throughout the planning period; however, there will be no increased cost to the Regional Entities. NERC will continue to review the appropriateness of continued funding of existing reliability tools, with any proposed changes thereto subject to review and input from the Regional Entities, appropriate NERC Committees and working groups, and other affected parties.
- NERC and the Regional Entities will collaboratively work to build and develop ERO Enterprise applications supporting both NERC and Regional Entity operations that will maximize efficiency of technology hardware, consistency of application, resources and data security. These will be managed by a single Project Management Office (PMO) at

NERC. ERO Enterprise funding for the development and maintenance of Enterprise applications will be subject to the budget and funding limits set forth in the approved Business Plan and Budget. The FRCC will also continue to fund applications and systems to satisfy our regional business needs.

- Improved disaster recovery mechanisms and improved IT security procedures will increase capital and operating costs at the Regional Entities.

2015 Goals and Key Deliverables (Regional Entity Division)

- Support NERC's goals that will continue to improve the quality and content of Reliability Standards, including a cost effectiveness assessment of proposed standards.
- Continue to encourage stakeholder awareness and participation in the NERC standards development process through educational outreach efforts and participation in Standard Drafting Teams, the NERC Standards Committee and related subcommittees. Support NERC's efforts to develop the bulk power system risk profile and assess standards compared to the profile and address the most important risk gaps.
- Work with NERC and the other Regional Entities, to continue refinement, improvement and prioritization of risk based compliance monitoring efforts. Continue support of the Reliability Assurance Initiative, including providing the necessary training for compliance and enforcement staff.
- Work with NERC and the other Regional Entities to register entities commensurate with risk to the Bulk Power System (BPS). Support the implementation of any changes resulting from the registration review that began in 2014.
- Continue the implementation of the BES exception process which began mid-2014.
- Work with NERC and the other Regional Entities to hold the industry accountable for violations that create serious risk to the BPS. Improve consistency, quality, and timeliness of compliance monitoring and enforcement activities while utilizing more enforcement discretion for those violations that have minimal impact to the reliability of the BES.
- Continue to be a strong enforcement authority that is independent, without conflict of interest, objective and fair, using enforcement discretion when warranted and imposing penalties and sanctions that are commensurate with risk.
- Support an ERO culture of reliability excellence. Work with NERC and the other Regional Entities to facilitate a learning environment throughout the industry. Work to improve event causal analysis, communication of lessons learned, tracking of recommendations, and implementation of best practices.
- Continue to improve consistency, quality, timeliness and cost effectiveness of NERC and Regional Entity data collection, analysis systems and capabilities through process improvements and more effective coordination and collaboration.
- Support NERC's efforts to move toward and implement an outcome based approach in Reliability Assessments to achieve measureable improvements in the BES reliability. Risks will be identified and prioritized based on reliability impacts, cost/practicality assessments, projected resources, and emerging issues.

- Work closely with the other Regional Entities and NERC to ensure that the delegated functions are implemented consistently and rationally and to promote the success of the ERO as a collaborative enterprise. Perform delegated functions with independence, without conflict of interest, with objectivity and fairness and with increased transparency.
- Support the ERO in addressing and mitigating reliability risks. Work with NERC and the other Regional Entities and the industry to effectively address security vulnerabilities and threats. During crisis situations, support ERO sharing of information among industry, Regions, and government.

2015 Overview of Cost Impacts

The FRCC's proposed 2015 Regional Entity budgeted expenses and net fixed assets (see page 12) is $7,162,233, which is a $368,944 or 5.4% increase over the 2014 budget. The major drivers of this increase are the net effect of:

- Increased compliance software maintenance and development to reflect current costs from the vendor, implement changes necessary to implement RAI and for needed portal efficiencies and program improvements.
- Increased allocated General and Administrative expense due to implementing succession plans for key functions involving a temporary increase of 1 FTE for training to succeed an anticipated retirement
- Budgeted 3% annual merit increase.
- Reduced Medical Benefits expense based on actual experience.
- Decrease in legal fees due to in house legal support.

Statutory Accounting Methodology

The FRCC, in order to be consistent with all the regions, has modified its accounting reporting as follows:

- ERO assessments needed to fund working capital are reflected in the General and Administrative Program within Administrative Services.
- The majority of the Operating Expenses are accounted for within their related department's budget. If an expense cannot be specifically linked to a department, it is included in the General and Administrative Program, within Administrative Services.
- All expenses for the Administrative Services Programs, referred to as indirect expenses for 2015, are allocated to the delegated program areas by their respective FTEs and are shown on one line of each delegated program area Statement of Activities as "Indirect Expenses".
- Capital expenditures are broken out as fixed assets at the end of each statement of activities rather than being included in their related lines in the operating expenses section.
- Expenses include depreciation, but since funding is not being requested for depreciation expense, it has been deducted from the funding requirement for capital expenditures.

2015 Key Deliverables by Program

In 2015, FRCC will achieve the following key deliverables:

- **Reliability Standards Development** — Continue support of NERC in its efforts to improve the quality and content of Reliability Standards and to support NERC's implementation of a cost effectiveness assessment of proposed standards. Support NERC in its efforts to evaluate significant BPS events (Category 3 and above) to identify gaps in standards and address any gaps identified. Support NERCs plan to develop or modify the Reliability Standard Audit Worksheets (RSAWs) by the time a Reliability Standard is balloted. Develop regional reliability standards as needed to support NERC's prioritized work plan and provide increased coordination of standards development activities.
- **Compliance Monitoring and Enforcement** — Continue to support the development and implementation of the Reliability Assurance Initiative, including implementation of the ERO Auditor Handbook and Manual and implementation of the common methodology to assess risk and determine the scope of monitoring activities. Ensure timely and thorough mitigation of all violations of mandatory reliability standards with the most focus on those violations that create serious risk to the Bulk Electric System. Promote a strong culture of compliance excellence, reliability improvement, and risk-based methods among all registered entities in the FRCC Region.
- **Event Analysis** — Continue to support improved reliability through reporting and categorizing of system events and security incidents. Consistently analyze events and system performance for sequence, cause, and remediation to identify reliability risks and trend, and to inform standards, compliance, and other programs. Work to ensure that the industry is well informed of system events, emerging trends, risk analysis, lessons learned and expected actions. Provide timely written lessons learned and recommendations from events and provide all BPS system event reports to the industry through a secure portal.
- **Critical Infrastructure Protection and Cyber Security** — Facilitate, educate and support Registered Entities in complying with CIP reliability standards and responding to cyber security alerts. Facilitate a proactive action plan by industry that demonstrates effective identification and mitigation of security risks, including safeguarding of assets, developing mitigation alternatives, and preparing and testing recovery plans. Support the transition from CIP V3 to V5 including provision of necessary training to FRCC staff, and providing education and outreach to stakeholders to ensure their understanding of the technical aspects of the requirements.
- **Reliability Assessments** — Provide annual, seasonal, probabilistic, scenario and special reliability assessments of the reliability of the FRCC BES in accordance with definitions and requirements. Work with NERC and the other Regional Entities to develop and demonstrate BES performance metrics for the purpose of analyzing and trending reliability improvements and benefits, as well as risk/severity based methods. Work with NERC and the other Regional Entities to support the exception process for the evaluation of Exception Requests as permitted by the revised definition of the BES and the NERC Rules of Procedure.

- **Situation Awareness** — Continue to support NERC in maintaining and enhancing the current and future situation awareness capabilities that include near real-time information and communications protocols that meet the needs of FERC, NERC, and applicable Registered Entities. Issue and track security recommendation to protect the Bulk Power System. Share information learned in Situation Awareness with the Events Analysis program to develop relevant lessons learned.
- **Effective Financial Controls** — Continue to provide rigorous cost controls and efficient management of resources to remain an efficient provider of ERO delegated functions.

Long Term Business Planning

NERC and the Regional Entities continue to work together to improve the overall ERO business planning and budgeting process, including long-term resource and financial planning. The 2015 Business Plan and Budget process builds upon the improvements made over the past several years including face-to-face meetings, conference calls and exchanges of documentation among senior management and staff of NERC and Regional Entities regarding budget assumptions, resource requirements, and opportunities to improve operational efficiency and effectiveness.

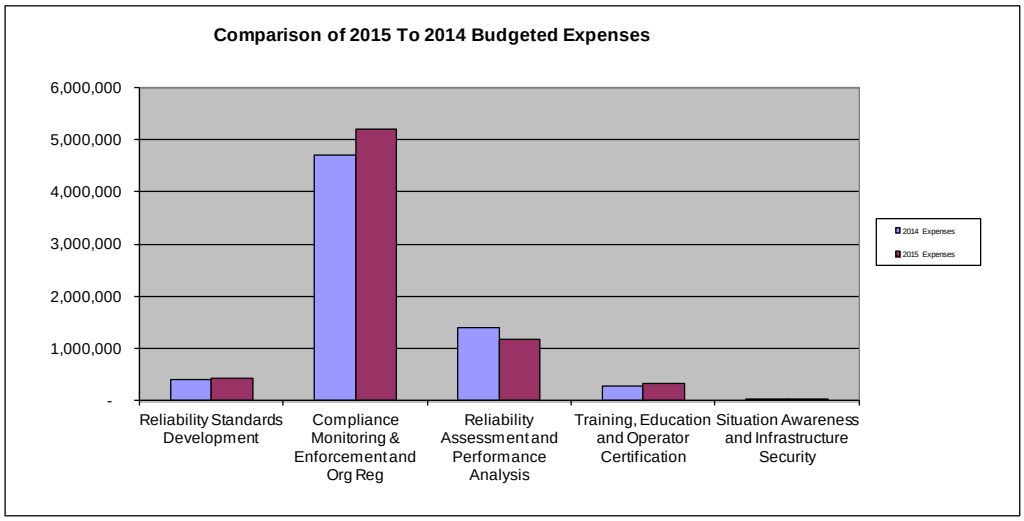
Throughout 2013 and into early 2014, NERC and the Regional Entities worked to develop a common operating model with defined roles and responsibilities that align with business planning goals, objectives, metrics and assumptions for the ERO Enterprise. As part of updating the ERO Strategic Plan, NERC and the Regional Entities consolidated five goals within the existing focus areas of standards; compliance, registration and certification; risks to reliability; and coordination and collaboration. A number of objectives and deliverables expected of the ERO Enterprise were identified. NERC and the Regional Entities added four overarching performance metrics to assess the overall effectiveness of the ERO Enterprise in addressing risk to the Bulk Power System and improving reliability. With the ERO Strategic Plan, the developed performance metrics, and the set of common assumptions, the 2015 Business Plan and Budgets of NERC and the Regional Entities will support and complement each other. The Shared Business Plan and Budget Assumptions (Exhibit A of the 2015 NERC Business Plan and Budget) incorporate assumptions affecting resource demands through the 2017 planning horizon.

NERC and the Regional Entities continue to work together to develop, strengthen and improve an integrated long term ERO business plan and budget that leverages and builds on the combined strengths and resources of NERC and the Regional Entities to improve the overall effectiveness and efficiency of ERO operations and improve the reliability of the BES of North America.

Detailed Business Plans and Budgets by Program

Details of the planning, operation, review, and adjustment for each program area are included in Section A. The corresponding budget details are shown in Section B. Below is an overall summary of the changes by program area.

Funding by Program	Budget 2014	Projection 2014	Budget 2015	Variance 2015 Budget v 2014 Budget	Variance %
Reliability Standards Development	409,591	409,592	423,143	13,552	3.3%
Compliance Monitoring & Enforcement and Org Reg	4,702,351	4,702,351	5,211,874	509,523	10.8%
Reliability Assessment and Performance Analysis	1,391,299	1,391,299	1,182,409	(208,890)	-15.0%
Training, Education and Operator Certification	272,310	297,679	321,525	49,215	18.1%
Situation Awareness and Infrastructure Security	19,380	19,380	23,281	3,901	20.1%
Total Funding All Sources	6,794,932	6,820,302	7,162,233	367,301	5.4%



This graphical representation does not include an allocation of working capital requirements among the Program Areas.

Total FTE's by Program Area	Budget 2014	Projection 2014	Direct FTEs 2015 Budget	Shared FTEs[1] 2015 Budget	Total FTEs 2015 Budget	Change from 2014 Budget
STATUTORY						
Operational Programs						
Reliability Standards Development	1.74	1.33	1.71		1.71	-0.03
Compliance Monitoring & Enforcement and Org Reg	19.26	18.25	19.77		19.77	0.51
Reliability Assessment and Performance Analysis	5.29	4.26		4.40	4.40	-0.89
Training, Education and Operator Certification	0.67	0.50		0.90	0.90	0.23
Situation Awareness and Infrastructure Security	0.08	0.06		0.09	0.09	0.01
Total FTEs Operational Programs	**27.04**	**24.40**	**21.48**	**5.39**	**26.87**	**-0.17**
Administrative Programs						
General & Administrative	3.36	3.57		4.04	4.04	0.68
Total FTEs Administrative Programs	**3.36**	**3.57**	**0.00**	**4.04**	**4.04**	**0.68**
Total FTEs	**30.40**	**27.97**	**21.48**	**9.43**	**30.91**	**0.51**

[1]A shared FTE is defined by NERC as an employee who performs both Statutory and Non-Statutory functions.

2014 Statutory Budget and Projection and 2015 Budget Comparisons

Statement of Activities, Fixed Assets Expenditures and Change in Working Capital
2014 Budget & Projection, and 2015 Budget

STATUTORY

	2014 Budget	2014 Projection	Variance 2014 Projection v 2014 Budget Over(Under)	2015 Budget	Variance 2015 Budget v 2014 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 5,488,057	$ 5,488,058	$ 0	6,237,838	$ 749,781
Penalty Sanctions	343,000	343,000	-	153,000	(190,000)
Total ERO Funding	**$ 5,831,057**	**$ 5,831,058**	**$ 0**	**$ 6,390,838**	**$ 559,781**
Membership Dues	$ -	$ -	$ -	$ -	$ -
Testing Fees	-	-	-	-	-
Services & Software	24,000	24,000	-	24,000	-
Workshops	90,000	115,369	25,369	90,000	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding	**$ 5,945,057**	**$ 5,970,427**	**$ 25,369**	**$ 6,504,838**	**$ 559,781**
Expenses					
Personnel Expenses					
Salaries	$ 3,806,631	3,630,346	$ (176,285)	$ 4,082,307	$ 275,676
Payroll Taxes	239,599	231,599	(8,000)	253,874	14,275
Benefits	657,255	608,521	(48,734)	579,483	(77,772)
Retirement Costs	602,881	594,403	(8,478)	666,669	63,788
Total Personnel Expenses	**$ 5,306,366**	**$ 5,064,869**	**$ (241,497)**	**$ 5,582,333**	**$ 275,967**
Meeting Expenses					
Meetings	$ 80,930	$ 48,138	$ (32,792)	$ 69,292	$ (11,638)
Travel	167,209	137,943	(29,266)	191,753	24,544
Conference Calls	18,771	14,732	(4,039)	9,482	(9,289)
Total Meeting Expenses	**$ 266,910**	**$ 200,813**	**$ (66,097)**	**$ 270,527**	**$ 3,617**
Operating Expenses					
Consultants & Contracts	$ 348,768	$ 416,262	$ 67,494	$ 393,718	$ 44,950
Office Rent	555,089	554,412	(677)	547,586	(7,503)
Office Costs	118,343	122,974	4,631	132,069	13,726
Professional Services	116,642	41,315	(75,327)	51,324	(65,318)
Miscellaneous	-	-	-	-	-
Depreciation	110,490	157,036	46,546	202,287	91,797
Total Operating Expenses	**$ 1,249,332**	**$ 1,291,999**	**$ 42,667**	**$ 1,326,984**	**$ 77,652**
Total Direct Expenses	**$ 6,822,608**	**$ 6,557,681**	**$ (264,927)**	**$ 7,179,844**	**$ 357,236**
Indirect Expenses	**$ (1,643)**	**$ -**	**$ 1,643**	**$ 0**	**$ 1,643**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses	**$ 6,820,965**	**$ 6,557,681**	**$ (263,284)**	**$ 7,179,844**	**$ 358,879**
Change in Assets	**$ (875,908)**	**$ (587,254)**	**$ 288,653**	**$ (675,006)**	**$ 200,902**
Fixed Assets					
Depreciation	$ (110,490)	$ (157,036)	$ (46,546)	$ (202,287)	$ (91,797)
Total Fixed Asset Purchases	82,814	129,422	46,608	184,676	101,862
Change in Fixed Assets	**27,676**	**27,614**	**(62)**	**17,611**	**(10,065)**
TOTAL BUDGET	$ 6,793,289	$ 6,530,067	$ (263,222)	$ 7,162,233	$ 368,944
TOTAL CHANGE IN WORKING CAPITAL	**$ (848,232)**	**$ (559,640)**	**$ 288,591**	**$ (657,395)**	**$ 190,837**
FTEs	30.40	27.97	(2.43)	30.91	0.51

Section A – Statutory Programs
2015 Business Plan and Budget

Reliability Standards Development Program

Reliability Standards Development Program (in whole dollars)	2014 Budget	2015 Budget	Increase (Decrease)
Total FTEs	1.74	1.71	(0.03)
Direct Expenses	$ 369,582	$ 370,389	$ 807
Indirect Expenses	$ 40,021	$ 49,808	$ 9,787
Inc(Dec) in Fixed Assets	$ (12)	$ 2,946	$ 2,958
Total Funding Requirement	$ 409,591	$ 423,143	$ 13,552

Program Scope and Functional Description

The FRCC may develop, through the FRCC Regional Reliability Standards Development Process, separate Regional Reliability Standards that are specific to the FRCC Region and go beyond, add detail to, or implement NERC Reliability Standards. FRCC Regional Reliability Standards will not be inconsistent with or less stringent than NERC Reliability Standards.

The FRCC Regional Reliability Standards Development Process is an open, balanced and fair process that ensures all interested and affected parties have an opportunity to participate in the development of FRCC Regional Reliability Standards for the FRCC Region.

While the FRCC may develop separate Regional Reliability Standards, the preference is to support the development of continent wide reliability standards. The FRCC staff follows and participates in NERC's Standards Development Process. This includes FRCC standards staff participation in the NERC Standards Committee, the NERC Standards Committee Process Subcommittee, and NERC standards drafting teams as appropriate. In addition, the FRCC supports and encourages stakeholder awareness and participation in the NERC standards development process through educational outreach efforts at workshops, webinars and committee meetings.

2015 Key Assumptions

The key assumptions included in the Shared Business Plan and Budget Assumptions, Exhibit A, affecting the Reliability Standards Program include:

1. NERC will continue to focus on reaching a steady state, and improving quality and content of Reliability Standards. This will require the allocation of resources from NERC and the Regional Entities. The implementation of a cost effectiveness assessment of proposed standards and other reform activities are expected to require additional resources however the impacts are not fully known at this time.

2. The number of projects contained in NERC's Reliability Standards Development Plan is expected to increase over the planning period reflecting the transformation of standards to

a steady-state. However, the scope of these projects is expected to narrow as regulatory obligations in the form of directives and five-year reviews, Paragraph 81, and other recommendations are addressed.

3. The focus on improving the quality and content of standards will likely increase the demand on NERC, the Regional Entities and stakeholders to review and comment on proposed revisions to standards, support regulatory filings and support successful implementation of new standards as they become effective.

4. The number of interpretation and guidance requests is expected to remain low, reflecting the initiative to reach steady state and implementation of the Reliability Assurance Initiative (RAI).

5. NERC and the Regional Entities must provide sufficient resources to develop or modify the RSAWs by the time a Standard is balloted which is required to support the Reliability Standards Development Plan.

6. Activity associated with FRCC Regional Reliability Standards development is expected to remain low. FRCC will continue to keep several regional standards development projects on hold while NERC development, on standards addressing the same reliability issues, proceeds to a conclusion.

7. NERC and the Regional Entities will continue to provide communication and outreach opportunities, project level communications and will continue education and training for new or revised standards.

2015 Goals and Key Deliverables

The Standards Program objectives for 2015 are outlined below:

- Continue to follow and participate in NERC's Standards Development Process. This includes FRCC standards staff participation in the NERC Standards Committee, the NERC Standards Committee Process Subcommittee and on NERC standards drafting teams as appropriate.
- Continue to encourage stakeholder awareness and participation in the NERC standards development process.
- Continue to monitor the need for development of Regional Reliability Standards that are required by NERC Reliability Standards or are needed for reliability within the FRCC region.
- Assist the FRCC members and registered entities in following and understanding NERC standards development activities by increasing education and outreach programs to include:
    - Development and presentation at Standards Workshops, Webinars and committee meetings to address continent-wide and regional reliability issues.
    - Develop and deliver project level communications, education and training for new or revised reliability standards.
    - Review, analyze and identify potential Regional concerns associated with NERC Reliability Standards under development.

- Establish a stronger relationship with the FRCC Regional Entity Committee to fully vet and identify any concerns and assist in articulating the concern to standard drafting teams as appropriate.

Funding Sources and Requirements — Explanation of Increase (Decrease)

- **Personnel Expenses** – The slight decrease in the number of FTEs is due to the expectation of more time being spent in Reliability Assessment program implementing the NERC BES Definition and the BES Definition Exception Process and the expectation of more time being spent in review of Registered Entity registration. The increase in personnel expenses is due to budgeted annual merit increases partially offset by a reduction in Medical Benefit expense.
- **Meeting Expenses** - Less travel is expected in 2015 with the BES Standards Writing Project being complete.
- **Operating Expenses** – The decrease in Operating Expenses is primarily the anticipated decrease in legal fees partially offset by increased contract costs included in Contracts, Consultants and Software for a security improvement initiative.
- **Indirect Expenses -** The increase in Indirect Expense is the result of a succession plan for expected future retirements.
- **Fixed Assets –** The increase in Fixed Assets is due to increased physical and cyber security measures and planned replacement of old computer equipment.

Reliability Standards Development Program

Funding sources and related expenses for the reliability standards section of the 2015 business plan are shown in the table below.

Statement of Activities, Fixed Assets Expenditures and Change in Working Capital
2014 Budget & Projection, and 2015 Budget
Reliability Standards Development

	2014 Budget	2014 Projection	Variance 2014 Projection v 2014 Budget Over(Under)	2015 Budget	Variance 2015 Budget v 2014 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 387,520	$ 387,520	$ 0	$ 413,407	$ 25,887
Penalty Sanctions	$ 22,072	$ 22,072		9,737	(12,335)
Total ERO Funding	**$ 409,591**	**$ 409,592**	**$ 0**	**$ 423,143**	**$ 13,552**
Membership Dues	$ -	$ -	$ -	$ -	$ -
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	-	-	-	-	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding	**$ 409,591**	**$ 409,592**	**$ 0**	**$ 423,143**	**$ 13,552**
Expenses					
Personnel Expenses					
Salaries	$ 217,880	$ 173,035	$ (44,845)	$ 225,465	$ 7,585
Payroll Taxes	13,714	11,039	(2,675)	14,021	307
Benefits	33,809	23,651	(10,158)	32,602	(1,207)
Retirement Costs	34,595	28,420	(6,175)	36,074	1,479
Total Personnel Expenses	**$ 299,998**	**$ 236,145**	**$ (63,853)**	**$ 308,162**	**$ 8,164**
Meeting Expenses					
Meetings	$ 2,080	$ 969	$ (1,111)	$ 2,606	$ 526
Travel	24,913	16,324	(8,589)	17,469	(7,444)
Conference Calls	174	456	282	203	29
Total Meeting Expenses	**$ 27,167**	**$ 17,749**	**$ (9,418)**	**$ 20,278**	**$ (6,889)**
Operating Expenses					
Consultants & Contracts	$ 4,529	$ 5,222	$ 693	$ 7,381	$ 2,852
Office Rent	23,230	19,312	(3,918)	21,993	(1,237)
Office Costs	6,324	5,968	(356)	7,681	1,357
Professional Services	7,482	2,257	(5,225)	3,261	(4,221)
Miscellaneous	-	-	-	-	-
Depreciation	852	1,073	221	1,633	781
Total Operating Expenses	**$ 42,417**	**$ 33,832**	**$ (8,585)**	**$ 41,949**	**$ (468)**
Total Direct Expenses	**$ 369,582**	**$ 287,726**	**$ (81,856)**	**$ 370,389**	**$ 807**
Indirect Expenses	**$ 40,021**	**$ 37,186**	**$ (2,835)**	**$ 49,808**	**$ 9,787**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses	**$ 409,603**	**$ 324,912**	**$ (84,691)**	**$ 420,197**	**$ 10,594**
Change in Assets	**$ (12)**	**$ 84,680**	**$ 84,692**	**$ 2,946**	**$ 2,958**
Fixed Assets					
Depreciation	$ (852)	$ (1,073)	$ (221)	$ (1,633)	$ (781)
Total Fixed Asset Purchases	840	371	(469)	4,579	3,739
Change in Fixed Assets	**$ 12**	**$ 702**	**$ 690**	**$ (2,946)**	**$ (2,958)**
TOTAL BUDGET	$ 409,591	$ 324,210	$ (85,381)	$ 423,143	$ 13,552
TOTAL CHANGE IN WORKING CAPITAL	**$ -**	**$ 85,382**	**$ 85,382**	**$ -**	**$ -**
FTEs	1.74	1.33	(0.41)	1.71	(0.03)

Compliance Monitoring and Enforcement Program and Organization Registration and Certification Program

Compliance Monitoring and Enforcement and Organization Registration and Certification Program (in whole dollars)	2014 Budget	2015 Budget	Increase (Decrease)
Total FTEs	19.26	19.77	0.51
Direct Expenses	$ 4,281,909	$ 4,658,890	$ 376,981
Indirect Expenses	$ 442,994	$ 575,856	$ 132,862
Inc(Dec) in Fixed Assets	$ (22,552)	$ (22,872)	$ (320)
Total Funding Requirement	$ 4,702,351	$ 5,211,874	$ 509,523

Program Scope and Functional Description

Monitoring, evaluating, investigating and enforcing compliance with Reliability Standards by owners, operators and users of the BES, as well as the development and adoption of the reliability standards themselves, are at the core of FRCC's mission. Reliable operation of the BES is in the public interest, because it will benefit all owners, operators and users of the BES, and, ultimately, all users and consumers of electric power in the FRCC Region.

Compliance and Enforcement activities are carried out by the FRCC compliance staff and are independent of all users, owners and operators of the BES. Compliance activities are governed by the delegation agreement between the North American Electric Reliability Corporation (NERC) and the FRCC. Through a risk-based program of monitoring, evaluating, enforcing, and if necessary, the imposition of penalties and sanctions for noncompliance with Reliability Standards, FRCC will strive to increase the level of reliable operation of the BES in the FRCC Region.

The NERC Compliance Monitoring and Enforcement Program (CMEP) is the program used by the FRCC to monitor, assess, and enforce compliance with Reliability Standards within the FRCC Region. The FRCC compliance staff works with the compliance staff of the other Regional Entities and with NERC to achieve as much consistency and transparency as possible in the implementation of the CMEP. The development and implementation of the Reliability Assurance Initiative (RAI) throughout 2014 and into early 2015 provides the foundation and guidance for NERC and the Regional Entities in moving to a risk-based environment aimed at focusing on those risks that are most important to the reliability of the BES.

2015 Highlights Compliance Monitoring and Enforcement Processes

In 2015 the FRCC will monitor, assess and enforce compliance with Reliability Standards using seven (7) monitoring processes (Compliance Audits, Self-Certifications, Spot Checking, Compliance Investigations, Self-Reporting, Periodic Data Submittals, and Complaints) to collect information in order to make assessments of compliance to Reliability Standards. However as risk based monitoring activities increase, strong consideration will be given by NERC and the

Regions to modify the current three (3) and six (6) year audit cycles for registered entities. The rigor, scope, depth and recurrence of audits and spot checks will be assessed by the reliability risk and not a predetermined schedule.

Registration and Certification

The FRCC has registered the organizations responsible for complying with Reliability Standards in accordance with Section 500 of the NERC Rules of Procedure. Currently there are 69 Registered Entities with a total of 244 registered functions. Maintaining a complete and accurate registration database will be an ongoing activity. The FRCC will develop, maintain and provide to NERC accurate information on entity registration within the FRCC Region with updates as changes occur. NERC and the Regional Entities began a review of the organization registration process in 2014 which may result in changes to the registration process that could begin in 2015. While expectations of increased activity are associated with the implementation of the BES Exception Process mid-2014, there is some uncertainty in the amount of activity associated with registration and certification of registered entities. The FRCC may consider the reallocation of existing resources should the need arise for additional support in this area.

Enforcement and Mitigation

Enforcement actions taken by FRCC may include the imposition of remedial action directives, sanctions and penalties which are applied per the NERC Rules of Procedure. Mitigation of violations of the approved Reliability Standards remains central to the FRCC's reliability focus. Registered Entities found in violation of a Reliability Standard will be required to fully mitigate the violation regardless of any enforcement actions taken. The year 2014 continued to bring advances in enforcement discretion of violations with minimal impact to the reliability of the BES. This additional discretion will continue in 2015 through the development and implementation of the NERC Reliability Assurance Initiative allowing for more focus being placed on those violations that pose a more serious risk to the reliability of the BES.

2015 Key Assumptions

- Audits are expected to continue under the current three and six year schedules until NERC and the Regional Entities transition to a more risk-based approach to compliance monitoring as developed in the Reliability Assurance Initiative (RAI).
- Reliability risk profiles for all Registered Entities will be developed and audit scopes will be tailored to the risk profiles which may increase the depth and complexity of some audits and decrease the depth and complexity of others. The consistent approach to audit scope methodology being developed as part of the RAI in 2014 is expected to be used in early 2015.
- Integration of the assessment of Registered Entity internal controls programs as part of the compliance monitoring program will allow NERC and the Regional Entities to further prioritize risk based compliance monitoring activities. Greater emphasis on internal controls provides positive incentives for industry to demonstrate effective management of compliance programs that are focused on reliability, as well as place downward pressure on compliance resource requirements for industry, NERC and the Regional Entities.
- The use of spot checks and self-certifications is expected to increase as risk-based monitoring is implemented, but that should have little effect on FRCC's overall resource requirements. The implementation of the Reliability Assurance Initiative and the

expansion of the Find Fix and Track (FFT) process will require resources to complete the design and to begin implementing RAI for both compliance and enforcement.

- The approval of CIP V5 is anticipated to significantly increase the compliance monitoring activities. The effective date for compliance with the CIP Version 5 standards will be April 1, 2016 for High and Medium impact assets and April 1, 2017 for Low impact assets. The transition between V3 to V5 will be a mission critical activity for the ERO Enterprise in 2015. FRCC plans to support the ongoing CIP v5 transition plans and anticipates an expansion in the number of Registered Entities that require guidance during 2015. Additional training requirements will be necessary to support the transition and will affect the annual training commitments. For most CIP activities, the resource demands are expected to increase throughout the planning period.
- The number of non-CIP violations is expected to decrease as most registered entities have been audited and the standards and RSAWs have matured.
- The Technical Feasibility Exception (TFE) program will continue however the processing per the revised Appendix 4D, of the NERC Rules of Procedure, is expected to drive a less onerous process for TFE reporting and reviewing.
- Applications planned to be centralized, such as a common audit management tool, at NERC to improve consistency and efficiency, will require Regional Entity support and resources for development and implementation. A significant multiyear investment will be required to develop and implement the system which will be funded by NERC.
- NERC and the Regional Entities are expected to utilize consistent audit practices and focus on higher target reliability risks to increase efficiency and mitigate overall compliance costs.
- NERC and the Regional Entities will provide sufficient resources to develop or modify the RSAWs by the time a Standard is balloted which is required to support the Reliability Standards Development Plan.
- NERC and the Regional Entities must plan to support the training requirements necessary to meet the criteria set forth by the ERO Auditor Manual and Handbook and the Compliance Auditor Capabilities and Competency Guide. Regional Entities will be expected to provide training documents and other related compliance guidance to compliance staff, review Auditor job descriptions and properly reflect the guidance provided in the Compliance Auditor Capabilities and Competency Guide, perform a gap analysis to identify both individual training needs and organizational compliance resource needs, provide an assessment process to evaluate audit team competencies and capability needs, and put a training program in place that addresses initial and continuing training for capability and competency development.
- NERC will continue to budget and incur the cost of a unified learning management system (LMS) for the regional audit staff and work with the Regional Entities to consolidate training resources and promote better coordination, planning, delivery and management of training efforts across the ERO.
- Additional resources will be required, and increases to NERC and Regional Entity training budgets are expected to support certain training initiatives of the RAI. Regional Entities are expected to allocate resources to meet the training requirements for the compliance and enforcement staff that are associated with the implementation of the RAI.

- Maintaining budgeted qualified compliance and enforcement staff will continue to be a challenge driven by a limited pool of qualified people and an aging work force. Investments in training less experienced personnel are likely to increase.

2015 Goals and Key Deliverables

The Compliance Monitoring and Enforcement Program objectives for 2015 are outlined below:

- Continue to assess and update entity registration and certification. The FRCC will support the implementation of the changes resulting from the registration review that began in 2014.
- Support the development and implementation of NERC's Reliability Assurance Initiative, including providing the necessary training for compliance and enforcement staff. Enforce compliance with mandatory reliability standards in accordance with the CMEP and ROP while improving consistency, quality, timeliness and utilizing more enforcement discretion for those violations that have minimal impact to the reliability of the BES.
- Develop and maintain reliability risk profiles of all registered entities in the FRCC Region for use in the continued transition to a more risk-based compliance monitoring.
- Implement the ERO Auditor Handbook and Manual and continue to work with NERC Compliance staff and other Regional Entity Compliance staff to modify compliance procedures to increase consistency in the determination of violations and penalties.
- Implement the common methodology developed in 2014 to assess risk and determine scope of monitoring activities. Conduct periodic audits, spot checks, self-certifications, and compliance investigations as required by the NERC Compliance Monitoring and Enforcement Program.
- Continue to promote the self-identification of non-compliance by Registered Entities and utilize increased discretion as appropriate. Ensure timely and thorough mitigation of all violations of mandatory reliability standards.
- Promote a culture of compliance excellence through education, transparency, information sharing and incentives.

Funding Sources and Requirements — Explanation of Increase (Decrease)

- **Personnel Expenses** – The increase in FTEs and personnel expense can be primarily attributed to expected increased effort in the Organization Registration Program and the effect of having an addition to staff budgeted for May of 2014 for a full year in 2015. The increase in personnel expense is also due to a budgeted annual merit increase. These increases are partially offset by reduced expected benefit expenses based from medical expenses being less than anticipated in the 2014 budget.
- **Meeting Expenses** – Increased travel is expected in 2015 to meet expectations of NERC for meetings to ensure consistent implementation of the Reliability Assurance Initiative (RAI), RAI associated updates to the Auditor Handbook, and to support ERO IT development projects.
- **Operating Expenses** – Anticipated increased cost of the Compliance Software to implement RAI and NERC business rules, increased contract costs included in Contracts,

Consultants and Software for a security improvement initiative and the increased depreciation effect of the additions of same in 2014 and 2015 partially offset by an anticipated decrease in legal fees.

- **Indirect Expenses -** The increase in Indirect Expense is the result of a succession plan for expected future retirements.
- **Fixed Assets –** The increase in Fixed Assets is due to increased cost in enhancements of the Compliance Software, increased physical and cyber security measures and planned replacement of old computer equipment.

Compliance Monitoring and Enforcement Program and Organization Registration and Certification Program

Funding sources and related expenses for the compliance enforcement and organization registration and certification section of the 2015 business plan are shown in the table below.

Statement of Activities, Fixed Assets Expenditures and Change in Working Capital 2014 Budget & Projection, and 2015 Budget

Compliance Monitoring & Enforcement and Organization Registration & Certification

	2014 Budget	2014 Projection	Variance 2014 Projection v 2014 Budget Over(Under)	2015 Budget	Variance 2015 Budget v 2014 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 4,458,040	$ 4,458,040	$ -	$ 5,099,302	$ 641,262
Penalty Sanctions	244,311	244,311	-	112,572	(131,739)
Total ERO Funding	**$ 4,702,351**	**$ 4,702,351**	**$ -**	**$ 5,211,874**	**$ 509,523**
Membership Dues	$ -	$ -	$ -	$ -	$ -
Federal Grants	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	-	-	-	-	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding	**$ 4,702,351**	**$ 4,702,351**	**$ -**	**$ 5,211,874**	**$ 509,523**
Expenses					
Personnel Expenses					
Salaries	$ 2,411,701	$ 2,368,964	$ (42,737)	$ 2,611,174	$ 199,473
Payroll Taxes	151,798	151,129	(669)	162,386	10,588
Benefits	452,812	421,727	(31,085)	385,976	(66,836)
Retirement Costs	382,958	389,089	6,131	431,288	48,330
Total Personnel Expenses	**$ 3,399,269**	**$ 3,330,909**	**$ (68,360)**	**$ 3,590,824**	**$ 191,555**
Meeting Expenses					
Meetings	$ 4,915	$ 7,412	$ 2,497	$ 12,729	$ 7,814
Travel	92,966	81,240	(11,726)	122,194	29,228
Conference Calls	4,565	8,805	4,240	4,390	(175)
Total Meeting Expenses	**$ 102,446**	**$ 97,457**	**$ (4,989)**	**$ 139,313**	**$ 36,867**
Operating Expenses					
Consultants & Contracts	$ 119,235	$ 225,494	$ 106,259	$ 214,984	$ 95,749
Office Rent	406,366	413,633	7,267	404,082	(2,284)
Office Costs	69,926	74,111	4,185	80,150	10,224
Professional Services	83,069	30,900	(52,169)	37,762	(45,307)
Miscellaneous	-	-	-	-	-
Depreciation	101,598	148,536	46,938	191,775	90,177
Total Operating Expenses	**$ 780,194**	**$ 892,674**	**$ 112,480**	**$ 928,753**	**$ 148,559**
Total Direct Expenses	**$ 4,281,909**	**$ 4,321,040**	**$ 39,131**	**$ 4,658,890**	**$ 376,981**
Indirect Expenses	**$ 442,994**	**$ 509,116**	**$ 66,122**	**$ 575,856**	**$ 132,862**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses	**$ 4,724,903**	**$ 4,830,156**	**$ 105,253**	**$ 5,234,746**	**$ 509,843**
Change in Assets	**$ (22,552)**	**$ (127,805)**	**$ (105,253)**	**$ (22,872)**	**$ (320)**
Fixed Assets					
Depreciation	$ (101,598)	$ (148,536)	$ (46,938)	$ (191,775)	$ (90,177)
Total Fixed Asset Purchases	79,046	127,708	48,662	168,903	89,857
Change in Fixed Assets	**$ 22,552**	**$ 20,828**	**$ (1,724)**	**$ 22,872**	**$ 320**
TOTAL BUDGET	$ 4,702,351	$ 4,809,328	$ 106,977	$ 5,211,874	$ 509,523
TOTAL CHANGE IN WORKING CAPITAL	**$ -**	**$ (106,977)**	**$ (106,977)**	**$ -**	**$ -**
FTEs	19.26	18.25	(1.01)	19.77	0.51

Reliability Assessment and Performance Analysis Program

Reliability Assessment and Performance Analysis Program (in whole dollars)	2014 Budget	2015 Budget	Increase (Decrease)
Total FTEs	5.29	4.39	(0.90)
Direct Expenses	$ 1,270,439	$ 1,049,392	$ (221,047)
Indirect Expenses	$ 121,674	$ 127,871	$ 6,197
Inc(Dec) in Fixed Assets	$ (814)	$ 5,146	$ 5,960
Total Funding Requirement	$ 1,391,299	$ 1,182,409	$ (208,890)

Program Scope and Functional Description

The FRCC will assess the reliability of the BES in the FRCC region and will continue to ensure that the planned system is robust, reliable and stable. The FRCC will participate in Event Analysis Teams to analyze any disturbances that may occur within the FRCC region.

The FRCC performs transmission reliability studies in order to provide an assessment to NERC for its periodic NERC Reliability Assessments. These studies evaluate regional and inter-regional facilities. The FRCC prepares a minimum of three reliability assessments each year and a probabilistic assessment every other year in support of NERC Reliability Assessments:

- A 20 year long-term reliability assessment report
- A summer assessment report
- A winter assessment report
- A probabilistic long-term reliability assessment (biennial)

These reports evaluate electricity demand, the adequacy of supply and its deliverability, fuel reliability and the adequacy of the transmission system within the FRCC. The FRCC will prepare special reliability assessment reports as conditions warrant.

The FRCC Reliability Assessment and Performance Analysis Program (RA) will support NERC's efforts to move toward and implement an outcome based approach in Reliability Assessments to achieve measureable improvements in the BES reliability. Risks will be identified and prioritized based on reliability impacts, cost/practicality of assessments, projected resources, and emerging issues. The FRCC will support NERC's efforts for collection and analysis of data, as well as support any of NERC's special reliability assessments and the efforts related to the collection of data via the Generation Availability Data System (GADS), Transmission Availability Data System (TADS) and Demand Response Availability Data System (DADS). In addition, the FRCC will work with NERC to gather data and/or complete

analysis in support of U.S. Federal initiatives, including high impact/low frequency events such as geomagnetic disturbances, system frequency response analysis, climate change and other environmental regulations.

The FRCC will support a new ERO initiative focused on identifying essential reliability services and providing the industry with technical papers and guidelines as appropriate.

The FRCC actively participates in the Eastern Interconnection Reliability Assessment Group (ERAG) which is responsible for the Eastern Interconnection transmission models and inter-regional studies. The FRCC will support NERC's and ERAG's efforts to improve the data quality of the Eastern Interconnection (EI) transmission models and validate the performance of these models compared to system events. The FRCC is an active participant on the NERC Reliability Assessment Subcommittee which is responsible for performing an independent review of reliability assessments.

The FRCC Events Analysis Program will analyze or support the analysis of significant events and system performance that impact the BES within the FRCC Region. The FRCC will facilitate consistent identification of sequence, root cause and remediation to identify reliability risks and trends, and lessons learned. FRCC's analysis will result in the identification of any gaps in standards, compliance effectiveness, registration and risk controls effectiveness. The FRCC will provide lessons learned and recommendations from events and identified risks.

The FRCC will support NERC to improve event causal analysis, communication of lessons learned, tracking of recommendations, and implementation of best practices. The FRCC will support NERC to continue to improve consistency, quality, timeliness and cost effectiveness of NERC and Regional Entity data collection, analysis systems and capabilities through process improvements and more effective coordination and collaboration.

2015 Key Assumptions

- NERC will continue to incrementally improve definitions, refine data reporting requirements for Registered Entities and review adequate level of reliability related metrics used in reliability assessments.
- NERC and Regional Entities will be requested to gather data or perform analysis in support of federal initiatives related to critical infrastructure protection including high impact/low frequency, climate change, environmental regulations, and/or renewable energy initiatives. Generation Availability Data System (GADS), Spare Equipment Database (SED) and Demand Response Data System (DADS) collection will continue to be mandatory in 2015.
- NERC and the Regional Entities are expected to provide independent reviews of assessments to assure a high level of technical rigor.
- Implementation of the BES exception process will require the re-allocation of resources from several NERC and Regional Entity departments. The resources will be expected to manage the process execution, technical validation of the definition and exception requests, self-determined notification submittals and requests for registration and certification review. The resource impacts are not fully known at this time, but are expected to be driven by the number and complexity of exception requests, self-determined notification submittals and registration requests received.

- NERC has established an Essential Reliability Services Task Force that may have an impact on resource requirements in order to support the work of this task force which is expected to have weekly conference calls and two or three in person meetings.
- NERC will sustain a Reliability Assessment and Performance Analysis team with representatives from the Regional Entities to:
    - Develop and implement improved enterprise-based data collection and analysis systems and capabilities
    - Support the integration of RAPA information systems for modeling and data requirements and achieve timelines for delivering high quality reports
    - Develop, verify and validate quality reliability assessment and analyses model and data quality characteristics
    - Address impacts of new technologies, changing resource or demand resource composition, and environmental related regulations or legislation
    - Support the compilation of long-term sustainable Eastern Interconnection models
    - Provide technical resources and expertise to perform analyses as needed for standards development, compliance and enforcement activities
    - Support quality analysis and overall assessment of the geomagnetic disturbance (GMD) vulnerability, planning guides and planning standards.
- The number of "qualified system events" as defined in the NERC Events Analysis Process, is expected to remain steady (approximately 10 per month across North America). Greater collaboration with the region and the registered entity is leading to more detailed analysis and supporting the identification of reliability issues and challenges.

2015 Goals and Key Deliverables

The Reliability Assessment and Performance Analysis Objectives for 2015 are outlined below:

- Perform a reliability assessment of the FRCC Region to determine if the planned resources and proposed transmission expansion plans will meet the needs of the projected demand throughout the planning horizon.
- Support NERC in preparing its reliability assessment reports.
- Support the implementation of the BES exception process. This will include providing a technical review of exception requests that are submitted by the registered entities.
- Support the work of the newly created Essential Reliability Services Task Force by assigning an FRCC Staff person to support this NERC initiative.
- Evaluate, track and assess severity/risk and reliability metrics and risk indices – including providing support to update reliability metrics and risk indices.
- Support data gathering and reporting efforts for the Generating Availability Data System (GADS), the Transmission Availability Data System (TADS), Spare Equipment Database (SED) and Demand Response Availability Data System (DADS).

- Strengthen data collection and validation processes by designing, creating, testing and implementing data checking systems to accommodate the increasing amount of data NERC collects for its long-term, seasonal, operational, scenarios and special reliability assessments along with the databases supporting reliability performance assessments.
- Review and/or analyze significant events that impact the FRCC BES and work with NERC to identify the root causes of events that may be precursors of potentially more serious events.
- Assess past reliability performance for potential lessons learned.
- Maintain relationships with NERC, regulatory and governmental organizations involved with BES reliability (e.g., Florida Public Service Commission (FPSC), Department of Energy (DOE), FERC, Energy Information Administration (EIA), etc.).
- Maintain a databank of power flow, short circuit and dynamic models to use in planning and evaluating future systems and current operating conditions.
- Work with ERAG Multi-Area Modeling Working Group (MMWG) to develop Eastern Interconnection steady-state and dynamics models and develop model validation processes.
- Conduct Loss of Load Probability and the Scenario Analysis studies as needed.

Funding Sources and Requirements — Explanation of Increase (Decrease)

- **Personnel Expenses** – In 2014, the committee structure was streamlined to reduce the amount of time that staff spent preparing for meetings and participating in meetings. Previously, the FRCC conducted business associated with Reliability Assessments in both the Operating Committee and the Planning Committee. This approach resulted in staff members attending multiple meetings each month to cover the same topics. With the revised structure, all Regional Entity activities will be conducted in one forum; the new Regional Entity Committee and Compliance Forum (RECCF). In addition to consolidating the Regional Entity activities under the RECCF, it was also determined that the RECCF will not need to meet monthly, but will meet face-to-face six times in 2015. This new construct will allow FRCC staff to complete the Reliability Assessment deliverables much more efficiently and drives the decrease to FTEs and personnel expenses.
- **Meeting Expenses** – With the formation of the RECCF, there will be fewer meetings required to complete the RA deliverables decreasing Meeting Expenses.
- **Operating Expenses** –The decrease is due to an anticipated decrease in legal fees and a reduction in certain consultant expenses which have been consistently over-budgeted.
- **Indirect Expenses -** The increase in Indirect Expense is the result of a succession plan for expected future retirements.
- **Fixed Assets –** The increase in Fixed Assets is due to increased physical and cyber security measures and planned replacement of old computer equipment.

Reliability Assessment and Performance Analysis Program

Funding sources and related expenses for the reliability assessment and performance analysis section of the 2015 business plan are shown in the table below.

Statement of Activities, Fixed Assets Expenditures and Change in Working Capital 2014 Budget & Projection, and 2015 Budget

Reliability Assessment and Performance Analysis

	2014 Budget	2014 Projection	Variance 2014 Projection v 2014 Budget Over(Under)	2015 Budget	Variance 2015 Budget v 2014 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 1,300,196	$ 1,300,196	$ -	$ 1,133,412	$ (166,784)
Penalty Sanctions	67,103	67,103	-	24,997	(42,106)
Total ERO Funding	**$ 1,367,299**	**$ 1,367,299**	**$ -**	**$ 1,158,409**	**$ (208,890)**
Membership Dues	$ -	$ -	$ -	$ -	$ -
Testing Fees	-	-	-	-	-
Services & Software	24,000	24,000	-	24,000	-
Workshops	-	-	-	-	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding	**$ 1,391,299**	**$ 1,391,299**	**$ -**	**$ 1,182,409**	**$ (208,890)**
Expenses					
Personnel Expenses					
Salaries	$ 662,404	$ 552,292	$ (110,112)	$ 580,711	$ (81,693)
Payroll Taxes	41,693	35,234	(6,459)	36,114	(5,579)
Benefits	99,378	84,437	(14,941)	82,646	(16,732)
Retirement Costs	105,185	90,711	(14,474)	92,914	(12,271)
Total Personnel Expenses	**$ 908,660**	**$ 762,674**	**$ (145,986)**	**$ 792,385**	**$ (116,275)**
Meeting Expenses					
Meetings	$ 6,674	$ 1,307	$ (5,367)	$ 1,612	$ (5,062)
Travel	43,265	34,637	(8,628)	47,375	4,110
Conference Calls	8,543	1,437	(7,106)	447	(8,096)
Total Meeting Expenses	**$ 58,482**	**$ 37,381**	**$ (21,101)**	**$ 49,434**	**$ (9,048)**
Operating Expenses					
Consultants & Contracts	$ 192,989	$ 130,637	$ (62,352)	$ 122,547	$ (70,442)
Office Rent	70,623	61,640	(8,983)	56,646	(13,977)
Office Costs	13,480	12,843	(637)	14,617	1,137
Professional Services	22,829	7,204	(15,625)	8,398	(14,431)
Miscellaneous	-	-	-	-	-
Depreciation	3,376	4,213	837	5,365	1,989
Total Operating Expenses	**$ 303,297**	**$ 216,537**	**$ (86,760)**	**$ 207,573**	**$ (95,724)**
Total Direct Expenses	**$ 1,270,439**	**$ 1,016,592**	**$ (253,847)**	**$ 1,049,392**	**$ (221,047)**
Indirect Expenses	**$ 121,674**	**$ 118,694**	**$ (2,980)**	**$ 127,871**	**$ 6,197**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses	**$ 1,392,113**	**$ 1,135,286**	**$ (256,827)**	**$ 1,177,263**	**$ (214,850)**
Change in Assets	**$ (814)**	**$ 256,013**	**$ 256,827**	**$ 5,146**	**$ 5,960**
Fixed Assets					
Depreciation	$ (3,376)	$ (4,213)	$ (837)	$ (5,365)	(1,989)
Total Fixed Asset Purchases	2,562	1,186	(1,376)	10,511	7,949
Change in Fixed Assets	**$ 814**	**$ 3,027**	**$ 2,213**	**$ (5,146)**	**$ (5,960)**
TOTAL BUDGET	$ 1,391,299	$ 1,132,259	$ (259,040)	$ 1,182,409	$ (208,890)
TOTAL CHANGE IN WORKING CAPITAL	**$ -**	**$ 259,040**	**$ 259,040**	**$ -**	**$ -**
FTEs	5.29	4.26	(1.03)	4.40	(0.89)

Training, Education, and Operator Certification Program

Training, Education and Operator Certification Program (in whole dollars)	2014 Budget	2015 Budget	Increase (Decrease)
Total FTEs	0.67	0.91	0.24
Direct Expenses	$ 257,163	$ 295,452	$ 38,289
Indirect Expenses	$ 15,410	$ 26,506	$ 11,096
Inc(Dec) in Fixed Assets	$ (263)	$ (433)	$ (170)
Total Funding Requirement	$ 272,310	$ 321,525	$ 49,215

Program Scope and Functional Description

The FRCC is a NERC-approved Continuing Education (CE) Provider. The FRCC System Operator Subcommittee (SOS) develops and delivers training in which FRCC grants NERC CE hours to those individuals who successfully complete a course. FRCC will utilize the NERC database to accommodate the recordkeeping requirements for the continuing education program. Maintaining the reliability of the BES requires informed and trained personnel. The FRCC supports training activities through its staff and its System Operator Subcommittee which reports to the FRCC Operating Committee.

The FRCC provides educational workshops and web based seminars to improve Registered Entity understanding of the FRCC CMEP, NERC Standards Development and CIP topics and trends. These outreach efforts are aimed at improving the effectiveness, understanding of and adherence to NERC reliability initiatives. The workshops also improve the working relationships between the FRCC Regional Entity program areas and the Registered Entities within the FRCC region.

System Operator Certification Program

The FRCC SOS identifies and manages annual training activities for the FRCC System Operators and provides information to FRCC members regarding the NERC training standards and any issues they may have related to system operators obtaining/retaining required NERC Certification.

The training and education program activities are carried out by FRCC's professional/technical staff and SOS members possessing the appropriate technical knowledge and competencies. In addition, vendors that specialize in System Operator training are also used. Providing the FRCC training and education programs helps to achieve a high level of knowledge and competence among the operating personnel in the performance of their reliability-related functions.

Compliance Workshops

Compliance workshops will be held in the spring and fall of 2015 consisting of three (3) sessions each. These workshops will be aimed at providing updates to the Registered Entities on

compliance procedures, instructions on changes to FRCC compliance website, lessons learned for previous violations and providing sufficient and appropriate evidence in a compliance audit. The entities will also be apprised of changes in rules and expectations of NERC and FERC with regard to the CMEP. The effect on compliance monitoring as a result of on-going changes in the NERC and Regional Reliability Standards will also be addressed.

In addition, there will be at least one (1) CIP Compliance Workshop that will address technical aspects of the CIP Reliability Standards, including, providing quality evidence, lessons learned and compliance processes specific to the monitoring and enforcement of the CIP standards. In addition, particular focus will be made on the transition from CIP V3 to CIP V5 standards.

In addition to the face to face venues, in 2015 FRCC compliance staff projects holding at least three (3) webinars (two sessions each) that will address specific topics that may be identified by registered entities or by emerging trends within the FRCC.

Standards Workshops

The FRCC Standards Department will be supporting and participating in various FRCC sponsored workshops (e.g., FRCC Compliance Workshops and FRCC SOS seminars) throughout 2015. The Standards Department contribution to the workshops will be designed to promote stakeholder awareness of Reliability Standards activities as well as education and training for new or revised Reliability Standards. In addition, the FRCC Standards Department plans to hold at least four (4) workshops or webinars that will educate stakeholders on the NERC Reliability Standards Development Procedure, and specific changes to existing reliability standards or specifics on new reliability standards. To help encourage stakeholder participation at the continent-wide level, the workshops will provide stakeholders with details of associated NERC Reliability Standards Development Projects, identifying key areas that may be of concern or interest to the stakeholders and identifying areas that are in need of industry support.

2015 Key Assumptions

- The Operating Personnel Certification program is expected to remain at steady state therefore no significant changes are expected in System Operator Certification CEH requirements through 2015.
- The System Operator Certification Program and Continuing Education Program will continue to be self-funded through a fee based structure for the exams and applications for approval of continuing education activities.
- The Regional Entities are expected to help determine training needs and anticipate areas of support for standards, compliance monitoring and enforcement and information technology (IT) for their staffs and stakeholders.

2015 Goals and Key Deliverables

The training, education and operator certification program objectives for 2015 are outlined below:

- Provide assistance to Regional Entity members in any issues they may have related to System Operator Certification.

- Conduct the annual system operator training seminars over a five (5) week period, with two (2) days each for the training. The training seminars involve from two (2) to four (4) FRCC staff members, as well as industry volunteers who participate as presenters. This activity is funded primarily through registration fees.
- Host FRCC Compliance Workshops and Webinars open to all FRCC Members and Registered Entities aimed at providing updates on compliance procedures, instructions on changes to compliance tools, changes associated with the implementation of the RAI and guidance on the providing of appropriate and sufficient evidence in a compliance audit.
- Host Reliability Standards Workshops and Webinars open to all FRCC Members and Registered Entities aimed at providing information concerning reliability standards under development, as well as the identification of technical concerns or issues that may impact the reliability of the FRCC BES.
- Conduct FRCC Reliability Standards Department presentations to support multiple training objectives (i.e., FRCC Compliance Workshops and FRCC SOS Seminars) to promote stakeholder awareness of continent wide and regional standards activities.
- Work with NERC and the other Regional Entities to achieve improvements in the coordination, content and manner of internal and external training programs.

Funding Sources and Requirements — Explanation of Increase (Decrease)

- **Personnel Expenses** – The increase in FTEs and Personnel Expenses is due to more time planned to be spent on training and education of registered entities in elements pertaining to the Reliability Assurance Initiative and in expectation of the transition to CIP Version 5. The increase in personnel expense is also due to a budgeted annual merit increase.
- **Meeting Expenses** – The decrease in Meeting Expenses is due to the anticipation that the cost for the SOS meeting facility will be less than it has been in the past.
- **Operating Expenses** –The increase in Operating Expenses is due to the cost of a security improvement initiative offset by an anticipated decrease in legal fees.
- **Indirect Expenses -** The increase in Indirect Expense is the result of a succession plan for expected future retirements.

Training, Education, and Operator Certification Program

Funding sources and related expenses for the training, education, and operator certification section of the 2015 business plan are shown in the table below.

Statement of Activities, Fixed Assets Expenditures and Change in Working Capital 2014 Budget & Projection, and 2015 Budget

Training, Education and Operator Certification

	2014 Budget	2014 Projection	Variance 2014 Projection v 2014 Budget Over(Under)	2015 Budget	Variance 2015 Budget v 2014 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 173,812	$ 173,812	$ -	$ 226,344	$ 52,532
Penalty Sanctions	8,499	8,499	-	5,182	(3,317)
Total ERO Funding	**$ 182,310**	**$ 182,310**	**$ -**	**$ 231,525**	**$ 49,215**
Membership Dues	$ -	$ -	$ -	$ -	$ -
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	90,000	115,369	25,369	90,000	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding	**$ 272,310**	**$ 297,679**	**$ 25,369**	**$ 321,525**	**$ 49,215**
Expenses					
Personnel Expenses					
Salaries	$ 83,896	$ 65,388	$ (18,508)	$ 119,243	$ 35,347
Payroll Taxes	5,281	4,171	(1,110)	7,416	2,135
Benefits	11,616	20,293	8,677	14,228	2,612
Retirement Costs	13,325	10,740	(2,585)	19,079	5,754
Total Personnel Expenses	**$ 114,118**	**$ 100,592**	**$ (13,526)**	**$ 159,966**	**$ 45,848**
Meeting Expenses					
Meetings	$ 67,248	$ 38,432	$ (28,816)	$ 52,311	$ (14,937)
Travel	5,996	5,674	(322)	4,616	(1,380)
Conference Calls	5,481	4,013	(1,468)	4,433	(1,048)
Total Meeting Expenses	**$ 78,725**	**$ 48,119**	**$ (30,606)**	**$ 61,360**	**$ (17,365)**
Operating Expenses					
Consultants & Contracts	$ 29,259	$ 51,473	$ 22,214	$ 37,104	$ 7,845
Office Rent	8,945	7,298	(1,647)	11,632	2,687
Office Costs	22,610	26,705	4,095	22,613	3
Professional Services	2,916	853	(2,063)	1,725	(1,191)
Miscellaneous	-	-	-	-	-
Depreciation	590	774	184	1,052	462
Total Operating Expenses	**$ 64,320**	**$ 87,103**	**$ 22,783**	**$ 74,126**	**$ 9,806**
Total Direct Expenses	**$ 257,163**	**$ 235,814**	**$ (21,349)**	**$ 295,452**	**$ 38,289**
Indirect Expenses	**$ 15,410**	**$ 14,055**	**$ (1,355)**	**$ 26,506**	**$ 11,096**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses	**$ 272,573**	**$ 249,869**	**$ (22,704)**	**$ 321,958**	**$ 49,385**
Change in Assets	**$ (263)**	**$ 47,810**	**$ 48,073**	**$ (433)**	**$ (170)**
Fixed Assets					
Depreciation	$ (590)	$ (774)	$ (184)	$ (1,052)	$ (462)
Total Fixed Asset Purchases	327	140	(187)	619	292
Change in Fixed Assets	**$ 263**	**$ 634**	**$ 371**	**$ 433**	**$ 170**
TOTAL BUDGET	$ 272,310	$ 249,235	$ (23,075)	$ 321,525	$ 49,215
TOTAL CHANGE IN WORKING CAPITAL	**$ -**	**$ 48,444**	**$ 48,444**	**$ -**	**$ -**
FTEs	0.67	0.50	(0.17)	0.90	0.23

Situation Awareness and Infrastructure Security Program

Situation Awareness and Infrastructure Security Program (in whole dollars)	2014 Budget	2015 Budget	Increase (Decrease)
Total FTEs	0.08	0.09	0.01
Direct Expenses	$ 19,932	$ 23,058	$ 3,126
Indirect Expenses	$ 1,840	$ 2,621	$ 781
Inc(Dec) in Fixed Assets	$ (2,392)	$ (2,398)	$ (6)
Total Funding Requirement	$ 19,380	$ 23,281	$ 3,901

Program Scope and Functional Description

The FRCC and the other Regional Entities support the ERO's situational awareness, cyber security preparedness and provide independent reliability information to policy makers and regulators. The Reliability Process for the FRCC Bulk Electric System documents the various reliability roles and functions that are coordinated, monitored and established by FRCC to provide situation awareness of the reliability of the FRCC BES. Two of the primary reliability goals of the FRCC are continuous improvement of the situation awareness of the operators within the FRCC and ensuring that adequate physical, operational and cyber security objectives are in place for the Regions' shared communications networks.

The FRCC supports NERC's situation awareness/event analysis coordination conference calls, the Situation Awareness for FERC, NERC and the Regions (SAFNR) Version 2 project and the FRCC satellite phone for situation awareness.

The NERC Rules of Procedure, Section 1000, requires that NERC monitor present conditions on the BES and provide leadership coordination, technical expertise and assistance to the industry in responding to events as necessary.

The Situation Awareness process will be used to support NERC and FERC's efforts for situation awareness of current system conditions.

2015 Key Assumptions

- NERC's Critical Infrastructure Department will have responsibility for the identification and management of the specialized critical infrastructure protection resources needed to support overall ERO CIP goals and objectives, as well as the specialized CIP resources needs of the other program areas (e.g., Standards, Compliance, Situation Awareness)

- NERC will continue to budget and incur costs to operate and maintain the software applications and systems known as Situational Awareness for NERC, FERC and Regions (SAFNR). NERC will also continue to fund the Grid Security Exercise (GridEx) and the Security Readiness Program to help Registered Entities with CIP compliance and security

awareness. The Regional Entities will be expected to provide subject matter experts for support of these activities.

- NERC will continue to fund, operate and maintain the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), with no increased cost to Regional Entities.

- There will be increased need and demand for CIP-related training and workshops. CIP compliance activities are budgeted within compliance. FRCC will continue to support and facilitate the development of NERC's secure portal for the management of alerts and infrastructure security information.

- There will be continued focus on detecting off-normal events to be analyzed by the responsible entity, FRCC or NERC.

2015 Goals and Key Deliverables

- Ensure that FRCC goals and activities support the mission to provide FERC, NERC and the staffs from the eight Regional Entities a visualization tool that enables the appropriate level of situation awareness for the near real-time conditions on the BES. Continue to work with the FRCC Reliability Coordinator to ensure that SAFNR and appropriate hardware and software resources are allocated. Continue to support future development of the situation awareness project capabilities.
- Issue and track security recommendations to protect the Bulk Power System. Share information learned in Situation Awareness with the Events Analysis program to develop relevant lessons learned.

Funding Sources and Requirements — Explanation of Increase (Decrease)

- **Personnel Expenses** – There is a de minimus (0.01) increase in FTEs. The increase in personnel expense is due to a budgeted annual merit increase.
- **Operating Expenses** –The increase in Operating Expenses is driven by the cost of a security improvement initiative offset by an anticipated decrease in legal fees.
- **Indirect Expenses -** The increase in Indirect Expense is the result of a succession plan for expected future retirements.

Situation Awareness and Infrastructure Security Program

Funding sources and related expenses for the situation awareness and infrastructure security section of the 2015 business plan are shown in the table below.

Statement of Activities, Fixed Assets Expenditures and Change in Working Capital
2014 Budget & Projection, and 2015 Budget
Situation Awareness and Infrastructure Security

	2014 Budget	2014 Projection	Variance 2014 Projection v 2014 Budget Over(Under)	2015 Budget	Variance 2015 Budget v 2014 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 18,365	$ 18,365	$ -	$ 22,769	$ 4,404
Penalty Sanctions	1,015	1,015	$ -	512	(502)
Total ERO Funding	**$ 19,380**	**$ 19,380**	**$ -**	**$ 23,281**	**$ 3,901**
Membership Dues	$ -	$ -	$ -	$ -	$ -
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	-	-	-	-	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding	**$ 19,380**	**$ 19,380**	**$ -**	**$ 23,281**	**$ 3,901**
Expenses					
Personnel Expenses					
Salaries	$ 10,017	$ 7,735	$ (2,282)	$ 12,256	$ 2,239
Payroll Taxes	631	493	(138)	762	131
Benefits	1,387	1,015	(372)	1,463	76
Retirement Costs	1,591	1,270	(321)	1,961	370
Total Personnel Expenses	**$ 13,626**	**$ 10,513**	**$ (3,113)**	**$ 16,442**	**$ 2,816**
Meeting Expenses					
Meetings	$ 13	$ 18	$ 5	$ 34	$ 21
Travel	69	68	(1)	99	30
Conference Calls	8	21	13	9	1
Total Meeting Expenses	**$ 90**	**$ 107**	**$ 17**	**$ 142**	**$ 52**
Operating Expenses					
Consultants & Contracts	$ 209	$ 234	$ 25	$ 401	$ 192
Office Rent	1,068	863	(205)	1,196	128
Office Costs	2,162	1,540	(622)	2,237	75
Professional Services	346	101	(245)	178	(168)
Miscellaneous	-	-	-	-	-
Depreciation	2,431	2,440	9	2,462	31
Total Operating Expenses	**$ 6,216**	**$ 5,178**	**$ (1,038)**	**$ 6,474**	**$ 258**
Total Direct Expenses	**$ 19,932**	**$ 15,798**	**$ (4,134)**	**$ 23,058**	**$ 3,126**
Indirect Expenses	**$ 1,840**	**$ 1,660**	**$ (180)**	**$ 2,621**	**$ 781**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses	**$ 21,772**	**$ 17,458**	**$ (4,314)**	**$ 25,679**	**$ 3,907**
Change in Assets	**$ (2,392)**	**$ 1,922**	**$ 4,314**	**$ (2,398)**	**$ (6)**
Fixed Assets					
Depreciation	$ (2,431)	$ (2,440)	$ (9)	$ (2,462)	$ (31)
Total Fixed Asset Purchases	39	17	(22)	64	25
Change in Fixed Assets	**$ 2,392**	**$ 2,423**	**$ 31**	**$ 2,398**	**$ 6**
TOTAL BUDGET	$ 19,380	$ 15,035	$ (4,345)	$ 23,281	$ 3,901
TOTAL CHANGE IN WORKING CAPITAL	**$ -**	**$ 4,345**	**$ 4,345**	**$ -**	**$ -**
FTEs	0.08	0.06	(0.02)	0.09	0.01

General and Administrative

General and Administrative (in whole dollars)	2014 Budget	2015 Budget	Increase (Decrease)
Total FTEs	3.36	4.04	0.68
Expenses	$ 623,583	$ 782,663	$ 159,080
Inc(Dec) in Fixed Assets	$ (1,643)	$ -	$ 1,643
Total Allocation to Statutory Programs	$ 621,940	$ 782,663	$ 160,723
Working Capital Requirement	$ (849,875)	$ (657,395)	$ 192,480

Program Scope and Functional Description Background

Charges included in General and Administrative are general legal expenses, executive time and expenses, human resources, information technology and accounting and finance. Every effort is made to charge items and time directly to activities and to designate as statutory or non-statutory. Undesignated items are shared costs between the Regional Entity Division and the Member Services Division and are allocated based on actual labor hours charged.

Legal and Regulatory Background

The FRCC General Counsel serves as the chief legal advisor to the President and CEO, Board of Directors, staff and stakeholders on all legal and regulatory matters affecting the FRCC. FRCC may use additional specialized legal resources on an as-needed basis, such as for tax matters, employee benefit plan issues and significant policy or FERC matters.

2015 Goals and Key Deliverables

- Assist the FRCC in carrying out its responsibilities as required by the approved delegation agreement between NERC and FRCC.
- Provide general corporate legal advice, legal training and timely, accurate filings to Regulatory authorities.

2015 Assumptions

In the 2015 Budget, as in the 2014 and 2013 budgets, there are no specific funds for hearings under CMEP Rules.

Information Technology Background

The FRCC maintains a number of tools and other support services for the benefit of its members, Registered Entities, Reliability Coordinator agent(s) and other system operators. These services include the FRCC Load and Resource Database (LRDB), the Compliance Tracking System (CTS), Compliance Issues Tracking System (CITS), Models on Demand (MOD), the FRCC corporate website, as well as other systems for collaboration, communication, data gathering and analysis.

Several years ago, NERC and the eight (8) Regional Entities formed an executive management group (known as the ERO EMG) which has, among other things, concentrated on developing enterprise-wide IT applications; with a goal of improving efficiency and consistency across NERC and the Regional Entities. As enterprise-wide projects are identified and prioritized by the ERO EMG, they are managed through a single Project Management Office (PMO) at NERC. The PMO has developed an ERO Enterprise application roadmap that will identify projects that NERC and the Regional Entities have agreed upon that are necessary to support improved efficiency and consistency across the ERO.

The NERC IT budget does not supplant the FRCC's need for IT expenditures for specific regional projects, but to the extent that agreed –upon ERO Enterprise applications provide greater efficiencies, there is no unnecessary, redundant expenditures contained in the FRCC business plan and budget.

2015 Goals and Key Deliverables

- Maintain IT and telecommunications systems and resources for efficient utilization of FRCC personnel.
- Improve the physical security of the FRCC office with additional access control and logging.
- Implement updated communications tools and technologies.
- Develop and enhance tools to automate and improve FRCC data collection and analysis processes.
- Expand IT support of the FRCC CMEP and provide additional metrics to improve accuracy and tracking within the CMEP processes.
- Continue the process of Document Management conversion in the Operating and Planning and Administrative programs.
- Implement needed changes to improve the FRCC corporate security posture as identified in the security assessment performed in 2014; improve overall security in all programs, enhance access controls with improved authentication mechanisms and increase security awareness and training.
- Improve disaster recovery and business continuity capabilities by implementing new geographically diverse data recovery solutions.

Human Resources Background

The FRCC has assembled an exceptional team of highly qualified employees to carry out the activities of the FRCC. The human resources department, in adherence with applicable federal and state laws, develops plans, and implements human resources policies and procedures, including staffing, compensation, benefits, employee relations, and training and development.

2015 Goals and Key Deliverables

- Recruit successful employees
- Improve human resource policies and procedures

- Provide management and training programs
- Ensure competitive employee compensation and benefits

Finance and Accounting Background

The FRCC will submit its annual budget for statutory and non-statutory activities to the FRCC Board of Directors for approval and then file the approved annual budget for statutory and non-statutory activities to NERC. This includes supporting materials such as a complete business plan and organizational chart, and the proposed expenditure of funds collected in sufficient detail to justify the requested funding collection and budget expenditures.

The Finance and Accounting Department will: direct the overall financial plans and accounting practices of the organization; oversee treasury, accounting, budget preparation and reporting, tax, and audit activities; and oversee financial and accounting system controls and standards.

2015 Goals and Key Deliverables

- Prepare the 2016 statutory and non-statutory budgets
- Report budget variances to the FRCC Corporate Compliance Finance and Audit Committee, the FRCC Board and to NERC on a quarterly basis
- Evaluate and advise on the impact of long-range planning
- Continue to provide on-going training to employees to ensure employees charge their time correctly
- Carry out succession planning and training in anticipation of retirement of key personnel

Funding Sources and Requirements — Explanation of Increase (Decrease)

- **Personnel Expenses** – The increase is the result of a succession plan for an anticipated retirement and the training costs associated with that transition. The increase in personnel expense is also due to a budgeted annual merit increase.
- Operating Expenses –The increase in Operating Expenses is driven by the increased contract costs included in Contracts, Consultants and Software for a security improvement initiative.

General and Administrative

Funding sources and related expenses for the general and administrative section of the 2015 business plan are shown in the table below.

Statement of Activities, Fixed Assets Expenditures and Change in Working Capital
2014 Budget & Projection, and 2015 Budget
General and Administrative

	2014 Budget	2014 Projection	Variance 2014 Projection v 2014 Budget Over(Under)	2015 Budget	Variance 2015 Budget v 2014 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ (849,875)	$ (849,875)	$ -	$ (657,395)	$ 192,480
Penalty Sanctions			-		
Total ERO Funding	**$ (849,875)**	**$ (849,875)**	**$ -**	**$ (657,395)**	**$ 192,480**
Membership Dues	$ -	$ -	$ -	$ -	$ -
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	-	-	-	-	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding	**$ (849,875)**	**$ (849,875)**	**$ -**	**$ (657,395)**	**$ 192,480**
Expenses					
Personnel Expenses					
Salaries	$ 420,733	$ 462,932	$ 42,199	$ 533,458	$ 112,725
Payroll Taxes	26,482	29,533	3,051	33,175	6,693
Benefits	58,253	57,398	(855)	62,568	4,315
Retirement Costs	65,227	74,173	8,946	85,353	20,126
Total Personnel Expenses	**$ 570,695**	**$ 624,036**	**$ 53,341**	**$ 714,554**	**$ 143,859**
Meeting Expenses					
Meetings	$ -	$ -	$ -	$ -	$ -
Travel	-	-	-	-	-
Conference Calls	-	-	-	-	-
Total Meeting Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Operating Expenses					
Consultants & Contracts	$ 2,547	$ 3,202	$ 655	$ 11,301	$ 8,754
Office Rent	44,857	51,666	6,809	52,037	7,180
Office Costs	3,841	1,807	(2,034)	4,771	930
Professional Services	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Depreciation	1,643	-	(1,643)	-	(1,643)
Total Operating Expenses	**$ 52,888**	**$ 56,675**	**$ 3,787**	**$ 68,109**	**$ 15,221**
Total Direct Expenses	**$ 623,583**	**$ 680,711**	**$ 57,128**	**$ 782,663**	**$ 159,080**
Indirect Expenses	**$ (623,583)**	**$ (680,711)**	**$ (57,128)**	**$ (782,663)**	**$ (159,080)**
Other Non-Operating Expenses	$ -	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Change in Assets	**$ (849,875)**	**$ (849,875)**	**$ -**	**$ (657,395)**	**$ 192,480**
Fixed Assets					
Depreciation	$ (1,643)	$ -	$ 1,643	$ -	1,643
Total Fixed Asset Purchases	-	-	-	-	-
Change in Fixed Assets	**$ 1,643**	**$ -**	**$ (1,643)**	**$ -**	**$ (1,643)**
TOTAL BUDGET	$ -	$ -	$ 1,643	$ -	$ 1,643
TOTAL CHANGE IN WORKING CAPITAL	**$ (849,875)**	**$ (849,875)**	**$ (1,643)**	**$ (657,395)**	**$ 190,837**
FTEs	3.36	3.57	0.21	4.04	0.68

Section B – Supplemental Financial Information
2015 Business Plan and Budget

Reserve Balance

Table B-1

Working Capital Reserve Analysis 2014-2015		
STATUTORY		
Beginning Working Capital Reserve (Deficit), December 31, 2013		1,966,888
Less: Penalty sanctions being held to be used as offset to 2015 assessments	[1]	**(153,000)**
Plus: 2014 ERO Funding (from LSEs or designees)		5,488,058
Plus: Projected 2014 Other funding sources		139,369
Plus: Penalty Sanctions Applied		343,000
Less: 2014 Projected expenses & capital expenditures		**(6,530,067)**
Projected Working Capital Reserve Surplus/(Deficit), December 31, 2014		**1,254,248**
Desired Working Capital Reserve, December 31, 2015	[2]	596,853
Less: Projected Working Capital Reserve, December 31, 2014		**(1,254,248)**
Increase(decrease) in assessments to achieve desired Working Capital Reserve		**(657,395)**
2015 Assessment for Expenses and Capital Expenditures		7,162,233
Less: Penalty Sanctions	[1]	**(153,000)**
Less: Other Funding Sources		**(114,000)**
Adjustment to achieve desired Working Capital Reserve		**(657,395)**
2015 Assessment		6,237,838

[1] Represents collections prior to June 30, 2014.

[2] On June 26, 2013, the FRCC Board of Directors set a working capital and operating working capital and operating reserve requirement of one (1) month of the total annual budget. The FRCC has a $1.5 million line of credit.

Breakdown by Statement of Activity Sections

The following detailed schedules are in support of the Table on page 13, of the 2015 FRCC Business Plan and Budget. All significant variances have been disclosed by program area in the preceding pages.

Penalty Sanctions

Penalty monies received prior to June 30, 2014 are to be used to offset assessments in the 2015 Budget, as documented in the NERC Policy – ACCOUNTING, FINANCIAL STATEMENT AND BUDGETARY TREATMENT OF PENALTIES IMPOSED AND RECEIVED FOR VIOLATIONS OF RELIABILITY STANDARD. Penalty monies received from July 1, 2014 through June 30, 2015 will be used to offset assessments in the 2016 Budget.

All penalties received prior to June 30, 2014 are detailed below.

Allocation Method: Penalty sanctions received have been allocated to the following statutory programs to reduce assessments: Reliability Standards; Compliance Monitoring & Enforcement and Organization Registration & Certification; Reliability Assessments and Performance Analysis; Training, Education and Operator Certification; and Situation Awareness and Infrastructure Security. Penalty sanctions are allocated based upon the number of FTEs in the Program divided by the aggregate total FTEs in the Programs receiving the allocation.

Table B-2

Penalty Sanctions Received On or Prior to June 30, 2014	Date Received	Amount Received
Penalty #1	10/25/2013	$ 38,000
Penalty #2	11/26/2013	100,000
Penalty #3	12/27/2013	7,000
Penalty #4	1/22/2014	2,000
Penalty #5	1/22/2014	2,000
Penalty #5	3/25/2014	4,000
Total Penalties Received		$ 153,000

Supplemental Funding

Table B-3

Outside Funding Breakdown By Program	Budget 2014	Projection 2014	Budget 2015	Variance 2015 Budget v 2014 Budget
Reliability Standards Development				
Total	$ -	$ -	$ -	$ -
Compliance Monitoring, Enforcement & Org. Registration	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -
Reliability Assessment and Performance Analysis				
Services & Software Fees	$ 24,000	$ 24,000	$ 24,000	$ -
	-	-	-	-
Total	$ 24,000	$ 24,000	$ 24,000	$ -
Training, Education and Operator Certification				
Workshops	$ 90,000	$ 115,369	$ 90,000	$ -
Total	$ 90,000	$ 115,369	$ 90,000	$ -
Situation Awareness and Infrastructure Security	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -
General and Administrative*				
Interest	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -
Total Outside Funding	$ 114,000	$ 139,369	$ 114,000	$ -

Assumes that no appreciable excess cash will be in the Bank Accounts and due to current low interest rates, no Interst is being budgeted.

Personnel Expenses

Table B-4

Personnel Expenses	Budget 2014	Projection 2014	Budget 2015	Variance 2015 Budget v 2014 Budget	Variance %
Salaries					
Total Salaries	$ 3,806,631	$ 3,630,346	$ 4,082,307	$ 275,676	7.24%
Total Payroll Taxes	$ 239,599	$ 231,599	$ 253,874	$ 14,275	5.96%
Benefits					
Workers Compensation	$ 10,241	$ 10,006	$ 11,179	$ 938	9.16%
Medical, LTD, STD Insurances	483,409	418,850	445,548	(37,861)	-7.83%
Employment Fees	-		-	-	
Education	100,319	88,994	100,676	357	0.36%
Employee Welfare & Contract Labor	18,936	55,671	22,080	3,144	16.60%
Relocation	44,350	35,000		(44,350)	-100.00%
Total Benefits	$ 657,255	$ 608,521	$ 579,483	$ (77,772)	-11.83%
Retirement					
Retirement Costs	$ 602,881	$ 594,403	$ 666,669	$ 63,788	10.58%
		-		-	
Total Retirement	$ 602,881	$ 594,403	$ 666,669	$ 63,788	10.58%
Total Personnel Costs	$ 5,306,366	$ 5,064,869	$ 5,582,333	$ 275,967	5.20%
FTEs	30.40	27.97	30.91	0.5	1.68%
Cost per FTE					
Salaries	$ 125,218	$ 129,794	$ 132,071	6,853	5.47%
Payroll Taxes	7,882	8,280	8,213	332	4.21%
Benefits	21,620	21,756	18,747	(2,873)	-13.29%
Retirement	19,832	21,251	21,568	1,736	8.76%
Total Cost per FTE	**$ 174,552**	**$ 181,082**	**$ 180,600**	**$ 6,048**	**3.46%**

Consultants and Contracts

Table B-5

Contracts & Consultants and Software & Licenses	Budget 2014	Projection 2014	Budget 2015	Variance 2015 Budget v 2014 Budget	Variance %
Contracts & Consultants and Software & Licenses					
Reliability Standards Development	$ 4,529	$ 5,222	$ 7,381	$ 2,852	62.97%
Compliance Monitoring & Enforcement and Org Reg	119,235	225,494	214,984	95,749	80.30%
Reliability Assessment and Performance Analysis	192,989	130,637	122,547	(70,442)	-36.50%
Training, Education and Operator Certification	29,259	51,473	37,104	7,845	26.81%
Situation Awareness and Infrastructure Security	209	234	401	192	91.87%
General and Administrative	2,547	3,202	11,301	8,754	343.70%
Total Contracts & Consultants and Software & Licenses	$ 348,768	$ 416,262	$ 393,718	$ 44,950	12.89%

"The amount for Consultants & Contracts in the Compliance Monitoring and Enforcement Program includes $16,000 in the 2014 budget, $25,500 in the projected 2014 and $3,500 in the 2015 budget estimated by SERC as the costs for SERC to perform compliance monitoring and enforcement responsibilities for the FRCC registered functions."

Office Rent

Table B-6

Office Rent	Budget 2014	Projection 2014	Budget 2015	Variance 2015 Budget v 2014 Budget	Variance %
Office Rent	$ 555,089	$ 554,412	$ 547,586	$ (7,503)	-1.35%
Total Office Rent	**$ 555,089**	**$ 554,412**	**$ 547,586**	**$ (7,503)**	**-1.35%**

Office Costs

Table B-7

Office Costs	Budget 2014	Projection 2014	Budget 2015	Variance 2015 Budget v 2014 Budget	Variance %
Telephone	$ 50,931	$ 49,865	$ 43,767	$ (7,164)	-14.07%
Internet	2,618	2,566	4,020	$ 1,402	53.55%
Office Supplies	14,172	19,313	17,719	$ 3,547	25.03%
Computer Supplies	4,226	4,191	9,322	$ 5,096	120.59%
Publications, Subscriptions & Dues	9,710	7,445	13,533	$ 3,823	39.37%
Postage	1,558	1,528	1,523	$ (35)	-2.25%
Equipment Maintenance	930	917	6,750	$ 5,820	625.81%
Copying	-			$ -	
Printing	23,166	26,334	21,069	$ (2,097)	-9.05%
Stationary Forms				$ -	
Commerical Insurance	11,032	10,815	14,366	$ 3,334	30.22%
Miscellaneous				$ -	
Total Office Costs	**$ 118,343**	**$ 122,974**	**$ 132,069**	**$ 13,726**	**11.60%**

Professional Services

Table B-8

Professional Services	Budget 2014	Projection 2014	Budget 2015	Variance 2015 Budget v 2014 Budget	Variance %
Outside Legal	$ 100,000	$ 25,000	$ 35,000	$ (65,000)	-65.00%
Accounting & Auditing Fees	16,642	16,315	16,324	$ (318)	-1.91%
Total Services	**$ 116,642**	**$ 41,315**	**$ 51,324**	**$ (65,318)**	**-56.00%**

Other Non-Operating Expenses

Table B-9

Other Non-Operating Expenses	Budget 2014	Projection 2014	Budget 2015	Variance 2015 Budget v 2014 Budget	Variance %
Interest Expense	$ -	$ -		$ -	
Office Relocation	-	-		$ -	
Total Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	

2015, 2016 and 2017 Projections

Table B-10

Statement of Activities and Capital Expenditures
2015, 2016 and 2017 Projections
Regional Entity

	2014 Budget	2015 Budget	$ Change 2015:2014 Over(Under)	% Chg 2015:2014 Over(Under)	2016 Projection	$ Change 2016:2015 Over(Under)	% Chg 2016:2015 Over(Under)	2017 Projection	$ Change 2017:2016 Over(Under)	% Chg 2017:2016 Over(Under)
Funding										
ERO Funding										
ERO Assessments	$ 5,488,057	$ 6,237,838	$ 749,781	13.66%	$ 7,271,064	$ 1,033,226	16.56%	$ 7,506,418	$ 235,354	3.24%
Penalty Sanctions	343,000	153,000	(190,000)	0.00%	-		-100.00%	-	-	
Total ERO Funding	**$ 5,831,057**	**$ 6,390,838**	**$ 559,781**	9.60%	**$ 7,271,064**	**$ 1,033,226**	13.77%	**$ 7,506,418**	**$ 235,354**	3.24%
Membership Dues	$ -	$ -	$ -		$ -	$ -		$ -	$ -	
Testing Fees	-	-	-		-	-		-	-	
Services & Software	24,000	24,000	-	0.00%	24,000	-	0.00%	24,000	-	0.00%
Workshops	90,000	90,000	-	0.00%	90,000	-	0.00%	90,000	-	0.00%
Interest	-	-	-		-	-		-	-	
Miscellaneous	-	-	-		-	-		-	-	
Total Funding	**$ 5,945,057**	**$ 6,504,838**	**$ 559,781**	9.42%	**$ 7,385,064**	**$ 1,033,226**	13.53%	**$ 7,620,418**	**$ 235,354**	3.19%
Expenses										
Personnel Expenses										
Salaries	$ 3,806,631	$ 4,082,307	$ 275,676	7.24%	$ 4,204,776	$ 122,469	3.00%	$ 4,330,919	$ 126,143	3.00%
Payroll Taxes	239,599	253,874	14,275	5.96%	261,490	7,616	3.00%	269,335	7,845	3.00%
Benefits	657,255	579,483	(77,772)	-11.83%	594,062	14,579	2.52%	609,082	15,020	2.53%
Retirement Costs	602,881	666,669	63,788	10.58%	686,264	19,595	2.94%	706,447	20,183	2.94%
Total Personnel Expenses	**$ 5,306,366**	**$ 5,582,333**	**$ 275,967**	5.20%	**$ 5,746,592**	**$ 164,259**	2.94%	**$ 5,915,783**	**$ 169,191**	2.94%
Meeting Expenses										
Meetings	$ 80,930	$ 69,292	$ (11,638)	-14.38%	$ 69,588	$ 296	0.43%	$ 69,892	$ 304	0.44%
Travel	167,209	191,753	24,544	14.68%	192,612	859	0.45%	193,497	885	0.46%
Conference Calls	18,771	9,482	(9,289)	-49.49%	9,564	82	0.86%	9,648	84	0.88%
Total Meeting Expenses	**$ 266,910**	**$ 270,527**	**$ 3,617**	1.36%	**$ 271,764**	**$ 1,237**	0.46%	**$ 273,037**	**$ 1,273**	0.47%
Operating Expenses										
Consultants & Contracts	$ 348,768	$ 393,718	$ 44,950	12.89%	$ 422,443	$ 28,725	7.30%	$ 448,117	$ 25,674	6.08%
Office Rent	555,089	547,586	(7,503)	-1.35%	559,532	11,946	2.18%	571,837	12,305	2.20%
Office Costs	118,343	132,069	13,726	11.60%	134,291	2,222	1.68%	136,578	2,287	1.70%
Professional Services	116,642	51,324	(65,318)	-56.00%	52,864	1,540	3.00%	54,450	1,586	3.00%
Miscellaneous	-	-	-		-	-		-	-	
Depreciation	110,490	202,287	91,797	83.08%	202,897	610	0.30%	203,525	628	0.31%
Total Operating Expenses	**$ 1,249,332**	**$ 1,326,984**	**$ 77,652**	6.22%	**$ 1,372,027**	**$ 45,043**	3.39%	**$ 1,414,507**	**$ 42,480**	3.10%
Total Direct Expenses	**$ 6,822,608**	**$ 7,179,844**	**$ 357,236**	5.24%	**$ 7,390,383**	**$ 210,539**	2.93%	**$ 7,603,327**	**$ 212,944**	2.88%
Indirect Expenses	**$ (1,643)**	$ 0	$ 1,643		**$ 0**	**$ 1,643**	0.00%	**$ -**	**$ 212,944**	-100.00%
Other Non-Operating Expenses	**$ -**	$ -	$ -		**$ -**	**$ -**		**$ -**	**$ -**	
Total Expenses	**$ 6,820,965**	**$ 7,179,844**	**$ 358,879**	5.26%	**$ 7,390,383**	**$ 212,182**	2.93%	**$ 7,603,327**	**$ 425,889**	2.88%
Change in Assets	**$ (875,908)**	**$ (675,006)**	**$ 200,902**	-22.94%	**$ (5,319)**	**$ 821,044**	-99.21%	**$ 17,091**	**$ (190,534)**	-421.32%
Fixed Assets										
Depreciation	$ (110,490)	$ (202,287)	$ (91,797)	83.08%	$ (202,897)	$ (610)	0.30%	$ (203,525)	$ (628)	0.31%
Total Fixed Asset Purchases	82,814	184,676	101,862	123.00%	197,578	12,902	6.99%	220,616	23,038	11.66%
								-	-	
Change in Fixed Assets	**$ 27,676**	**$ 17,611**	**$ (10,065)**	-36.37%	**$ 5,319**	**$ (12,292)**	-69.80%	**$ (17,091)**	**$ (22,410)**	-421.32%
TOTAL BUDGET	$ 6,793,289	$ 7,162,233	$ 368,944	5.43%	$ 7,385,064	$ 224,474	3.11%	$ 7,620,418	$ 448,299	3.19%
TOTAL CHANGE IN WORKING CAPITAL	**$ (848,232)**	**$ (657,395)**	**$ 190,837**	-22.50%	**$ -**	**$ 808,752**	-100.00%	**$ -**	**$ (212,944)**	
FTEs	30.40	30.91	0.51	1.68%	30.91	-	0.00%	30.91	-	0.00%

Section C – Non-Statutory Activities
2015 Business Plan and Budget

Member Services Activities (in whole dollars)	2014 Budget	2015 Budget	Increase (Decrease)
Total FTEs	16.8	18.4	1.5
Direct Expenses	7,454,381	8,422,053	967,672
Indirect Expenses	-	-	-
Inc(Dec) in Fixed Assets	1,614	(30,071)	(31,685)
Total Funding Requirement	7,455,995	8,391,982	935,987

Non-Statutory Functional Scope Background

The Member Services (MS) division of the FRCC provides, coordinates and administers a variety of services relating to the reliable planning and operation of the BES within the FRCC Region. These services are carried out by the FRCC Member Services Planning Committee (PC) and the FRCC Member Services Operating Committee (OC), various subcommittees, task forces and working groups, as well as FRCC Staff.

Member Services Objectives

- Ensure the reliability of the BES in the FRCC region.
- Coordination, planning, operation and maintenance of reliable bulk electricity supply in the FRCC region.

Membership and Governance

The FRCC's Members in the Member Services Division include investor-owned utilities, cooperative utilities, municipal utilities, power marketers and independent power producers. Current membership is 23 FRCC Members in 2014 and is not expected to change in 2015.

The activities of FRCC are directed by its Board of Directors. The Board is comprised of senior level executives from the FRCC membership.

Planning Committee (PC) Functional Scope

The PC promotes the reliability of the BES within the FRCC Region by assessing and encouraging generation and transmission adequacy. The PC assesses generation adequacy by performing a reliability assessment taking into account projected load and resources. The PC, through the FRCC Regional Transmission Planning Process, provides a vehicle for ensuring that transmission planning within the FRCC will provide for the development of a robust transmission network within the FRCC Region. The Regional Transmission Planning Process is a coordinated transmission planning process that evaluates all BES and non-BES transmission facilities. The major goal of this process is to ensure that the planning of transmission facilities

will meet the needs of all market participants in a coordinated, open and transparent transmission planning environment.

The FRCC will continue to develop, on an annual basis, a Regional Transmission Plan following the Regional Transmission Planning Process. The Regional Transmission Planning process will be revised to incorporate the planning principles from FERC Order 1000. The Regional Plan is based on the Ten Year Site Plans that are required to be submitted to the Florida Public Service Commission (FPSC) on April 1st of each year. The FRCC participates in an annual Ten Year Site Plan Workshop held by the FPSC where the results of resource and transmission adequacy assessments are presented.

The FRCC PC relies on the following subordinate groups to achieve its goals: Resource Working Group (RWG), Stability Working Group (SWG), and the Transmission Working Group (TWG).

The PC, supported by FRCC MS staff, has the primary responsibility of the Planning Authority (PA) function including implementation of all applicable PA NERC Reliability Standards.

Resource Working Group
The RWG performs reliability assessments of FRCC resource adequacy for the future 10-year period for peninsular Florida based on individual utility information that was the basis of their respective EIA-411 and Ten Year Site Plan filings with the Florida Public Service Commission. These reliability assessments are based upon the FRCC resource adequacy criteria.

Stability Working Group
The SWG is responsible for assessing the dynamic performance of the FRCC BES under various credible system conditions. In addition, the SWG performs the following assessments and studies: Coordination and performance of Special Protection Systems, the effectiveness of FRCC under-frequency load shedding program and coordination with other protection and control systems, Extreme Event Study and other assessments in support of the FRCC Regional Transmission Planning Process. The SWG annually develops FRCC dynamic models.

Transmission Working Group
The TWG engages in active coordination of transmission planning within the FRCC Region under the direction of the FRCC Planning Committee in support of the FRCC Regional Transmission Planning Process. The TWG annually performs a FRCC Long Range Study, sensitivity studies as directed by the PC, evaluates Transmission Service Requests and evaluates Generator Interconnection Service Requests. In addition, the TWG annually develops a FRCC Transmission Map, FRCC power flow models and FRCC short circuit models.

Operating Committee (OC) Functional Scope

The primary goal of the OC is to promote the reliability of the BES within the FRCC Region. The OC is responsible for the coordination, operations planning, operation and maintenance of the interconnected systems operating in the Region. The OC's primary reliability goals include effective implementation of the Regional Reliability Plan (*Reliability Process for the FRCC Bulk Electric System*), continuous improvement of operator awareness and communications and ensuring that adequate physical, operational and cyber security objectives are in place for the Region's shared communications network. The OC subordinate groups include the Operating

Reliability Subcommittee (ORS), Data Exchange Working Group (DEWG), Fuel Reliability Working Group (FRWG), Operations Planning Working Group (OPWG), Telecommunications Subcommittee (TS), System Protection and Control Subcommittee (SPCS) and the Critical Infrastructure Protection Subcommittee (CIPS). The OC ensures reliable operations are maintained through the implementation and oversight of the FRCC Reliability Coordinator (RC) functions as established in the Regional Reliability Plan.

The FRCC RC responsibilities include the real-time operating function and the next-day operations planning function. The RC tasks are performed by a designated agent of the FRCC with direction and oversight by FRCC committees and support staff. The designated agent performs real-time operations and next-day planning operations. FRCC staff supports Regional reliability by performing the roles of the Operations Planning Coordinator (OPC), and State Capacity Emergency Coordinator (SCEC) as defined in the *Reliability Process for the FRCC Bulk Electric System* document.

The FRCC RC function is accountable to the FRCC OC who has overall responsibility of the administration, development and implementation of operating procedures provided by the ORS for the NERC Operations & Planning (Non-CIP) Standards.

The FRCC continues to improve FRCC PA and RC compliance management programs under the Member Services Division based on the evolving regulatory requirements. The FRCC has improved its oversight of PA and RC functions by creating an independent Member Services Regulatory Department with a dedicated Regulatory Director who reports directly to the FRCC President and CEO and who has direct access to the FRCC Board of Directors. This position is responsible for the implementation, maintenance and oversight of the FRCC Internal Compliance Program (ICP) including all compliance activities for the FRCC registered entity functions and is the primary interface for all regulatory activities associated with the FRCC Member Services committees and is the FRCC liaison between external Compliance Enforcement Authorities.

Operating Reliability Subcommittee (ORS)

The ORS provides overall administration for the development and implementation of operating procedures and other reliability matters including the oversight of the FRCC RC function for Operating and Planning (non-CIP) NERC Standards. The ORS reviews and assesses regional import and export limits, scheduled transmission outages, real-time system reliability, events analysis, information and data exchange and other reliability issues. The ORS provides formal oversight and implementation of the Reliability Process for the FRCC Bulk Electric System which establishes the reliability responsibilities of the various entities within the Region and specifically monitors the agent responsible for performing the RC functions.

Data Exchange Working Group (DEWG)

The DEWG, subordinate to the ORS, supports the real-time data needs of the FRCC Reliability Coordinator and other operating entities. It is also responsible for developing methodologies to facilitate the exchange of real-time, modeling and other operational data to help ensure reliable electric power system operations. Accurate modeling of the FRCC BES is essential to maintaining situation awareness and ensuring reliability. Within the FRCC, operating entities provide system data via the FRCC Reliability Data Link (RDL). The FRCC RDL receives electric system reliability data from the operating entities on a real-time basis and allows the data to be made available.

Fuel Reliability Working Group (FRWG)
The FRWG, also subordinate to the ORS, has been established to deal with matters relating to fuel and impacts to BES reliability. Specifically, the FRWG provides the administrative oversight of a Regional fuel reliability forum that studies the interdependencies of fuel availability and electric reliability and supports coordinated Regional responses to fuel issues and fuel emergencies.

Operations Planning Working Group (OPWG)
The OPWG, as a part of the ORS, has been established to provide oversight, guidelines and procedures to the FRCC Operations Planning Coordinator (OPC) in accordance with the Reliability Process for the FRCC BES document. The OPWG focuses on BES reliability and developing processes and documentation that support regional reliability and adherence to the NERC Reliability Standards as they relate to the OPC function.

FRCC Telecommunications Subcommittee (TS)
The TS provides oversight for the TS budget which is included in the OC budget. The primary purpose of the TS is to ensure that adequate and redundant communications facilities are made available to the operating entities within the FRCC, including the FRCC Reliability Coordinator. The TS administers the FRCC Hotline program, Satellite phone program, and also ensures that reliable and redundant communications are maintained by the Eastern Interconnect Data Sharing Network, Inc. (EIDSN). All TS programs are non-statutory and support the Reliability Coordinator functions; with the exception of the FRCC satellite phone (located at the FRCC office) which is a tool that can be used by the Regional Entity to perform situation awareness and thus is budgeted as statutory.

FRCC System Protection and Control Subcommittee (SPCS)
The FRCC System Protection and Control Subcommittee (SPCS) has primary responsibility for the coordination of protection and control systems within the FRCC region, including regional disturbance monitoring equipment, review of protective mis-operations, protection related disturbance analysis and implementation of specific regional programs and procedures including the assessments of the FRCC Under-Frequency Load Shedding Program. The SPCS also reviews and coordinates system protection and control equipment installations, settings, protection philosophies and testing criteria within the region, when installations impact multiple entities. The SPCS serves as an important forum for sharing subject matter expert guidance and lessons learned / best practices for equipment issues and protection coordination.

FRCC Critical Infrastructure Protection Subcommittee (CIPS)
The purpose of the FRCC CIPS is to enhance the physical and cyber security of the critical BES infrastructure in the FRCC Region, with an emphasis on protecting, preventing, limiting and recovering from malicious activities directed at the FRCC critical energy infrastructure. The CIPS provides guidance to the OC on matters of critical energy infrastructure security, including cyber and physical security. The CIPS provides advice to the OC including implementation of all applicable FRCC RC CIP-002 through CIP-009 Reliability Standards.

Major 2015 Cost Impacts

The FRCC's proposed 2015 Members Services budgeted expenses and net fixed assets are $8,391,982, which is a $935,987 or 12.6% increase over the 2014 budgeted expenses. The cost impacts by function of this increase are:

Planning Committee (PC)
The Member Services Planning Committee (PC) expenses for 2015 are made up of the PC Committee budget, as well as the administrative costs to provide support personnel for implementation of the FRCC Planning Authority (PA) functions and all other Member Services PC activities. In 2015, staff will spend additional time enhancing FRCC steady state planning studies and has budgeted $150,000 for additional stability studies to prepare to meet the requirements of the new NERC Transmission Planning (TPL) Standard. In addition, staff is expected to add one FTE in 2015 to support the implementation of FERC Order 1000 as recommended by the PC.

The 2015 PC budget is developed based on the activities of the Resource Working Group (RWG), the Stability Working Group (SWG) and the Transmission Working Group (TWG). These budgets are primarily for the labor involved in coordination activities performed by member representatives, software and meeting costs.

Operating Committee (OC)
The Member Services Operating Committee (OC) expenses for 2015 are made up of a 2015 OC budget as well as the administrative costs to provide support personnel for implementation of the FRCC Reliability Coordinator (RC) functions and other Member Services OC activities. In 2015, staff will spend additional time coordinating activities with member companies to ensure continued reliability and compliance with changing NERC Reliability Standards.

The 2015 OC budget is developed based primarily on the activities of the Operating Reliability Subcommittee (ORS), the Telecommunications Subcommittee (TS), the Fuel Reliability Working Group (FRWG) and the Critical Infrastructure Protection Subcommittee (CIPS). These budgets are related to, or in support of both the FRCC Reliability Coordinator (RC) and Member Services entity's reliability functions and includes consulting costs, contract costs, computer software purchases and expenses to support the associated activities. These budgets do not include FRCC staff salaries or associated personnel costs.

The administrative costs associated with the FRCC OC support personnel include FRCC staff that support implementation of the FRCC RC functions and staff that support overall OC activities. The staff includes dedicated employees as well as shared employees.

Funding Sources and Requirements — Explanation of Increase (Decrease)

- **Personnel Expenses** – The increase in FTEs is attributed to an additional employee in the planning area to support new long range planning activities, the effect of a complete year for the 2014 addition to staff to support the Reliability Coordinator function that was budgeted to be filled in mid-2014 and the result of the implementation of a succession plan for a key accounting position.
- **Operating Expenses** – The increase in Operating Expenses is attributed to increases in consultant and contractor costs for the RC and PA functions.

2014 Member Services Budget and Projection and 2015 Budget Comparisons

Statement of Activities, Fixed Assets Expenditures and Change in Working Capital
2014 Budget & Projection, and 2015 Budget
NON-STATUTORY MEMBER SERVICES

	2014 Budget	2014 Projection	Variance 2014 Projection v 2014 Budget Over(Under)	2015 Budget	Variance 2015 Budget v 2014 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ -	$ -	$ -	$ -	$ -
Penalty Sanctions	-	-	-	-	-
Total ERO Funding	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Membership Dues	$ 6,916,762	$ 6,916,762	$ -	8,240,106	1,323,344
Testing Fees	-	-	-	-	-
Services & Software	277,419	312,531	35,112	254,459	(22,960)
Workshops	-	-	-	20,000	20,000
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding	**$ 7,194,181**	**$ 7,229,293**	**$ 35,112**	**$ 8,514,565**	**$ 1,320,384**
Expenses					
Personnel Expenses					
Salaries	$ 2,108,824	$ 2,134,834	$ 26,010	$ 2,423,514	$ 314,690
Payroll Taxes	132,734	136,193	3,459	150,716	17,982
Benefits	350,795	320,232	(30,563)	351,746	951
Retirement Costs	328,267	343,386	15,119	387,762	59,495
Total Personnel Expenses	**$ 2,920,620**	**$ 2,934,645**	**$ 14,025**	**$ 3,313,738**	**$ 393,118**
Meeting Expenses					
Meetings	$ 37,515	$ 39,955	$ 2,440	$ 26,582	$ (10,933)
Travel	63,716	55,451	(8,265)	60,205	(3,511)
Conference Calls	27,108	30,959	3,851	45,286	18,178
Total Meeting Expenses	**$ 128,339**	**$ 126,365**	**$ (1,974)**	**$ 132,073**	**$ 3,734**
Operating Expenses					
Consultants & Contracts	$ 3,657,668	$ 3,843,855	$ 186,187	$ 4,260,160	$ 602,492
Office Rent	224,835	238,262	13,427	236,403	11,568
Office Costs	419,112	472,831	53,719	375,314	(43,798)
Professional Services	79,910	35,385	(44,525)	45,476	(34,434)
Miscellaneous	-	75,000	75,000	-	-
Depreciation	23,897	45,496	21,599	58,889	34,992
Total Operating Expenses	**$ 4,405,422**	**$ 4,710,829**	**$ 305,407**	**$ 4,976,242**	**$ 570,820**
Total Direct Expenses	**$ 7,454,381**	**$ 7,771,839**	**$ 317,458**	**$ 8,422,053**	**$ 967,672**
Indirect Expenses	$ -	$ -	**$ -**	**$ -**	**$ -**
Other Non-Operating Expenses	$ -	$ -	**$ -**	**$ -**	**$ -**
Total Expenses	**$ 7,454,381**	**$ 7,771,839**	**$ 317,458**	**$ 8,422,053**	**$ 967,672**
Change in Assets	**$ (260,200)**	**$ (542,546)**	**$ (282,346)**	**$ 92,512**	**$ (352,712)**
Fixed Assets					
Depreciation	$ (23,897)	$ (45,496)	$ (21,599)	$ (58,889)	$ (34,992)
Total Fixed Asset Purchases	25,511	78,929	53,418	28,818	3,307
	-	-			
Change in Fixed Assets	**$ (1,614)**	**$ (33,433)**	**$ (31,819)**	**$ 30,071**	**$ 31,685**
TOTAL BUDGET	$ 7,455,995	$ 7,805,272	$ 349,277	$ 8,391,982	$ 935,987
TOTAL CHANGE IN WORKING CAPITAL	**$ (261,814)**	**$ (575,979)**	**$ (314,165)**	**$ 122,583**	**$ 384,397**
FTEs	16.84	15.73	(1.11)	18.35	1.51

Personnel Analysis

Total FTE's by Program Area	Budget 2014	Projection 2014	Direct FTEs 2015 Budget	Shared FTEs[1] 2015 Budget	Total FTEs 2015 Budget	Change from 2014 Budget
NON-STATUTORY						
Operational Programs						
Operations Committee	10.48	9.94		10.27	10.27	-0.21
Planning Committee	3.27	3.52		4.57	4.57	1.30
Total FTEs Operational Programs	**13.75**	**13.46**	**0.00**	**14.84**	**14.84**	**1.09**
Administrative Programs						
General & Administrative	3.09	2.99		3.51	3.51	0.42
Total FTEs Administrative Programs	**3.09**	**2.99**	**0.00**	**3.51**	**3.51**	**0.42**
Total FTEs	**16.84**	**16.45**	**0.00**	**18.35**	**18.35**	**1.51**

[1]A shared FTE is defined by NERC as an employee who performs both Statutory and Non-Statutory functions.

Member Services Reserve Analysis — 2014 – 2015

Working Capital Reserve Analysis 2014-2015 NON-STATUTORY MEMBER SERVICES		
Beginning Working Capital Reserve (Deficit), December 31, 2013		587,073
Change in Post Retirement Benefit Obligation - Noncash Item		565,655
2014 Funding (from members)		6,916,762
2014 Projected Other funding sources		312,531
Total Cash Available 2014		8,382,021
Less: '2014 Projected expenses & capital expenditures		**(7,805,272)**
Projected Working Capital Reserve Surplus/(Deficit), December 31, 2014		**576,749**
Desired Working Capital Reserve, December 31, 2015	[1]	699,332
Less: Projected Working Capital Reserve, December 31, 2014		**(576,749)**
Increase(decrease) in assessments to achieve desired Working Capital Reserve		**122,583**
2015 Funding for Expenses and Capital Expenditures		8,391,982
Less: Other Funding Sources		**(274,459)**
Adjustment to achieve desired Working Capital Reserve		**122,583**
2015 Funding (reserve adjustment)		8,240,106

[1] On June 26, 2013, the FRCC Board of Directors set a working capital and operating working capital and operating reserve requirement of one (1) month of the total annual budget. The FRCC has a $1.5 million line of credit.

Section D – Additional Consolidated Financial Statements

2015 Business Plan and Budget

Section D — 2015 Additional Consolidated Financial Information

		Functions in Delegation Agreement							Non-Statutory Functions		
Statement of Activities and Capital Expenditures by Program 2014 Budget	Total	Statutory Total	Reliability Standards Development (Section 300)	Compliance Monitoring and Org Reg % Cert(Section 400 & 500)	Reliability Assessment and Performance Analysis (Section 800)	Training and Education (Section 900)	Situation Awareness and Infrastructure Security (Section 1000)	General and Administrative	Non-Statutory Total	Operating Committee	Planning Committee
Funding											
ERO Funding											
ERO Assessments	$ 6,237,838	$ 6,237,838	$ 413,407	$ 5,099,302	$ 1,133,412	$ 226,344	$ 22,769	$ (657,395)	$ -	$ -	$ -
Penalty Sanctions	153,000	153,000	9,737	112,572	24,997	5,182	512		-	-	-
Total ERO Funding	**6,390,838**	**6,390,838**	**423,143**	**5,211,874**	**1,158,409**	**231,525**	**23,281**	**(657,395)**	**-**	**-**	**-**
Membership Dues	$ 8,240,106	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,240,106	$ 6,792,087	$ 1,448,019
Testing Fees	-	-							-		
Services & Software	278,459	24,000			24,000				254,459	254,459	
Workshops	110,000	90,000				90,000			20,000	20,000	
Interest	-	-							-		
Miscellaneous	-	-							-		
Total Funding	**$ 15,019,403**	**$ 6,504,838**	**$ 423,143**	**$ 5,211,874**	**$ 1,182,409**	**$ 321,525**	**$ 23,281**	**$ (657,395)**	**$ 8,514,565**	**$ 7,066,546**	**$ 1,448,019**
Expenses											
Personnel Expenses											
Salaries	$ 6,505,821	$ 4,082,307	$ 225,465	$ 2,611,174	$ 580,711	$ 119,243	$ 12,256	$ 533,458	$ 2,423,514	$ 1,676,219	$ 747,295
Payroll Taxes	404,590	253,874	14,021	162,386	36,114	7,416	762	33,175	150,716	104,243	46,473
Benefits	931,229	579,483	32,602	385,976	82,646	14,228	1,463	62,568	351,746	235,709	116,037
Retirement Costs	1,054,431	666,669	36,074	431,288	92,914	19,079	1,961	85,353	387,762	268,195	119,567
Total Personnel Expenses	$ 8,896,071	$ 5,582,333	**$ 308,162**	**$ 3,590,824**	**$ 792,385**	**$ 159,966**	**$ 16,442**	**$ 714,554**	$ 3,313,738	$ 2,284,366	$ 1,029,372
Meeting Expenses											
Meetings	$ 95,874	$ 69,292	$ 2,606	$ 12,729	$ 1,612	$ 52,311	$ 34		$ 26,582	$ 18,286	$ 8,296
Travel	251,958	191,753	17,469	122,194	47,375	4,616	99		60,205	53,700	6,505
Conference Calls	54,768	9,482	203	4,390	447	4,433	9		45,286	30,491	14,795
Total Meeting Expenses	$ 402,600	$ 270,527	**$ 20,278**	**$ 139,313**	**$ 49,434**	**$ 61,360**	**$ 142**	**$ -**	$ 132,073	$ 102,477	$ 29,596
Operating Expenses											
Consultants & Contracts	$ 4,653,878	$ 393,718	$ 7,381	$ 214,984	$ 122,547	$ 37,104	$ 401	$ 11,301	$ 4,260,160	$ 4,036,905	$ 223,255
Office Rent	783,989	547,586	21,993	404,082	56,646	11,632	1,196	52,037	236,403	163,508	72,895
Office Costs	507,383	132,069	7,681	80,150	14,617	22,613	2,237	4,771	375,314	351,537	23,777
Professional Services	96,800	51,324	3,261	37,762	8,398	1,725	178		45,476	31,435	14,041
Miscellaneous	-	-							-		
Depreciation	261,176	202,287	1,633	191,775	5,365	1,052	2,462		58,889	50,230	8,659
Total Operating Expenses	$ 6,303,226	$ 1,326,984	**$ 41,949**	**$ 928,753**	**$ 207,573**	**$ 74,126**	**$ 6,474**	**$ 68,109**	$ 4,976,242	$ 4,633,615	$ 342,627
Total Direct Expenses	**$ 15,601,897**	**$ 7,179,844**	**$ 370,389**	**$ 4,658,890**	**$ 1,049,392**	**$ 295,452**	**$ 23,058**	**$ 782,663**	**$ 8,422,053**	**$ 7,020,458**	**$ 1,401,595**
Indirect Expenses	-	-	**49,808**	**575,856**	**127,871**	**26,506**	**2,621**	**(782,663)**			
Other Non-Operating Expenses	-	-	-	-	-	-	-	-	-	-	-
Total Expenses	**$ 15,601,897**	**$ 7,179,844**	**$ 420,197**	**$ 5,234,746**	**$ 1,177,263**	**$ 321,958**	**$ 25,679**	**$ -**	**$ 8,422,053**	**$ 7,020,458**	**$ 1,401,595**
Change in Assets	**$ (582,494)**	**$ (675,006)**	**$ 2,946**	**$ (22,872)**	**$ 5,146**	**$ (433)**	**$ (2,398)**	**$ (657,395)**	**$ 92,512**	**$ 46,088**	**$ 46,424**
Fixed Assets											
Depreciation	$ (261,176)	$ (202,287)	$ (1,633)	$ (191,775)	$ (5,365)	$ (1,052)	$ (2,462)	$ -	$ (58,889)	$ (50,230)	$ (8,659)
Total Fixed Asset Purchases	213,494	184,676	4579	168,903	10,511	619	64		28,818	11,545	17,273
Change in Fixed Assets	**$ 47,682**	**$ 17,611**	**$ (2,946)**	**$ 22,872**	**$ (5,146)**	**$ 433**	**$ 2,398**	**$ -**	**$ 30,071**	**$ 38,685**	**$ (8,614)**
TOTAL CHANGE IN WORKING CAPITAL	**$ (534,812)**	**$ (657,395)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (657,395)**	**$ 122,583**	**$ 84,773**	**$ 37,810**

Statement of Financial Position

Statement of Financial Position
2013 Audited, 2014 Projection, 2015 Budget and 2016 Projected

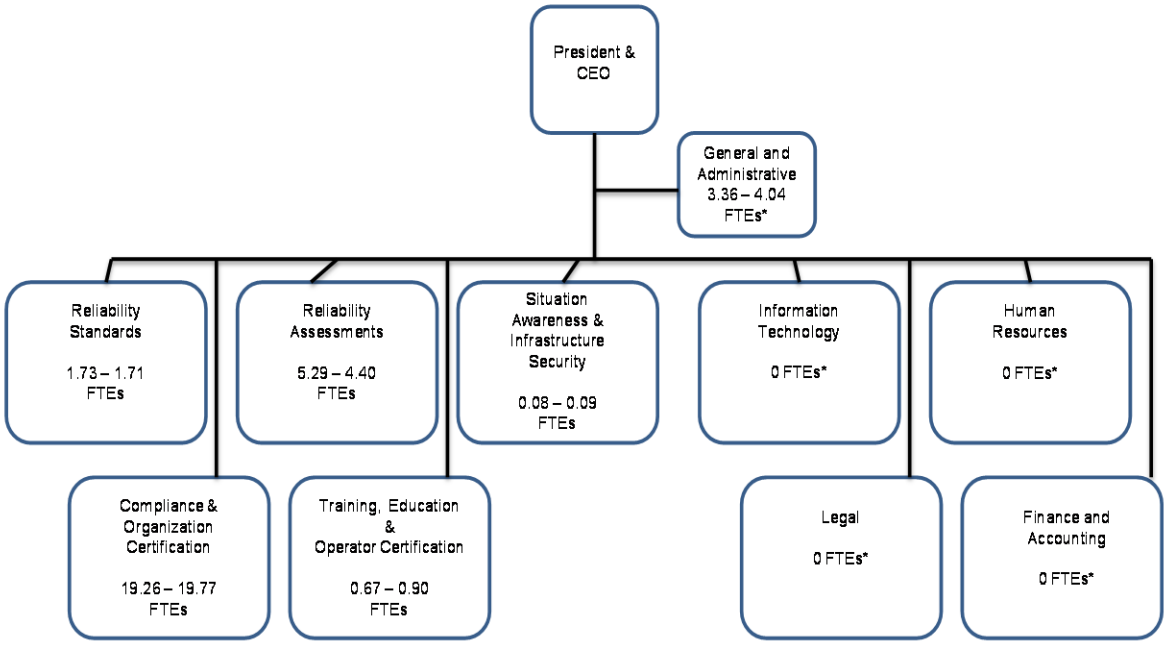
STATUTORY and NON-STATUTORY

	(Per Audit) 12/31/2013	Projected 12/31/2014	Budget 12/31/2015	Projected 12/31/2016
ASSETS				
Cash	6,558,632	4,763,059	3,577,263	3,665,908
Accounts receivable	2,855,070	2,955,070	3,155,070	3,355,070
Other receivables	-	-	-	-
Prepaid expenses and other current assets	18,526	15,000	15,000	15,000
Other Assets	259,175	150,000	150,000	150,000
Property and equipment (net of depreciation)	418,454	300,000	300,000	300,000
Total Assets	**10,109,857**	**8,183,129**	**7,197,333**	**7,485,978**
LIABILITIES AND NET ASSETS				
Liabilities				
Accounts payable and accrued expenses	2,556,119	2,540,000	1,800,000	1,900,000
Deferred income	3,111,955	3,657,736	3,846,312	3,957,406
Compliance Penalty Assessment	481,000	-	-	-
Accrued postretirement benefits obligation	1,406,822	1,477,163	1,551,021	1,628,572
Total Liabilities	**7,555,896**	**7,674,899**	**7,197,333**	**7,485,978**
Net Assets - unrestricted	2,553,961	508,230	-	-
Total Liabilities and Net Assets	**10,109,857**	**8,183,129**	**7,197,333**	**7,485,978**

Statutory Organizational Chart

Florida Reliability Coordinating Council, Inc.
Statutory Organization Chart

2014 Budgeted FTEs 30.40
2015 Budgeted FTEs 30.91



*All FTEs for Information Technology, Legal, Finance, and Human Resources, are recorded within General and Administrative

FRCC
Florida Reliability Coordinating Council, Inc.

FRCC 2015 Business Plan & Budget

(As Submitted to NERC and Posted for Comments on 5/16/2014)

(Not Approved by the FRCC Board of Directors)

NERC and Regional Entity Meeting with the NERC FAC

May 21, 2014

Reva R. Maskewitz - Controller

2015 Regional Entity Division Personnel Comparison

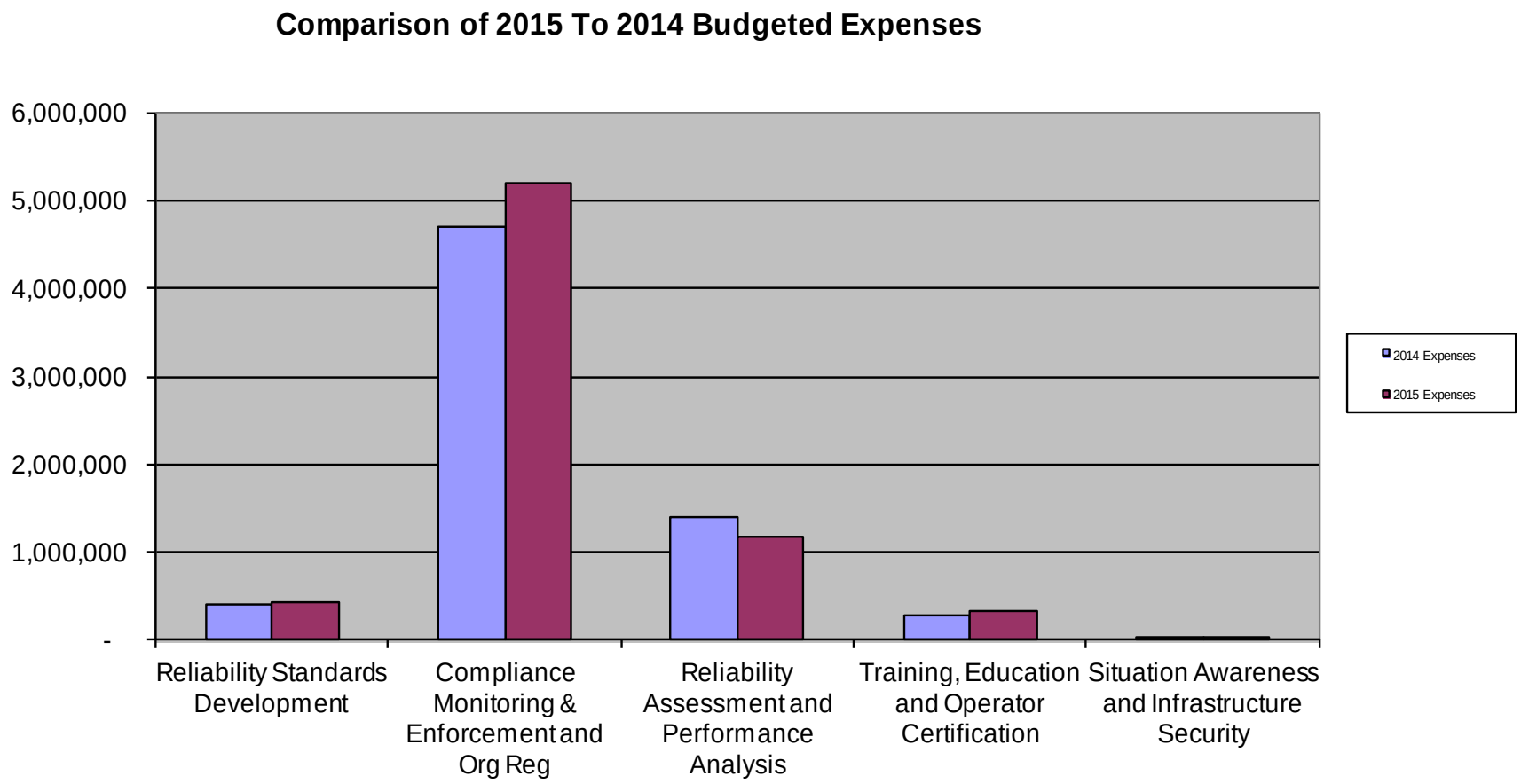
Total FTE's by Program Area	Budget 2014	Projection 2014	Direct FTEs 2015 Budget	Shared FTEs[1] 2015 Budget	Total FTEs 2015 Budget	Change from 2014 Budget
STATUTORY						
Operational Programs						
Reliability Standards Development	1.74	1.33	1.71		1.71	-0.03
Compliance Monitoring & Enforcement and Org Reg	19.26	18.25	19.77		19.77	0.51
Reliability Assessment and Performance Analysis	5.29	4.26		4.40	4.40	-0.89
Training, Education and Operator Certification	0.67	0.50		0.90	0.90	0.23
Situation Awareness and Infrastructure Security	0.08	0.06		0.09	0.09	0.01
Total FTEs Operational Programs	**27.04**	**24.40**	**21.48**	**5.39**	**26.87**	**-0.17**
Administrative Programs						
General & Administrative	3.36	3.57		4.04	4.04	0.68
Total FTEs Administrative Programs	**3.36**	**3.57**	**0.00**	**4.04**	**4.04**	**0.68**
Total FTEs	**30.40**	**27.97**	**21.48**	**9.43**	**30.91**	**0.51**

[1]A shared FTE is defined by NERC as an employee who performs both Statutory and Non-Statutory functions.

2015 RE Division Total Funding by Program Area

	2014	2015	% Change 2015:2014	$ Change 2015:2014
Reliability Standards Development	409,591	423,143	3.3%	13,552
Compliance Monitoring and Enforcement	4,700,708	5,211,874	10.9%	511,166
Reliability Assessment & Performance Analysis	1,391,299	1,182,409	-15.0%	(208,890)
Training, Education and Operator Certification	272,310	321,525	18.1%	49,215
Situational Awareness & Infrastructure Security	19,380	23,281	20.1%	3,901
Total Statutory Expenses & Net Fixed Assets	6,793,288	7,162,232	5.4%	368,944
Funding:				
Total Statutory Funding Assessment	5,488,056	6,237,837	13.7%	749,781
Pass ThruTraining & Education	90,000	90,000	0.0%	-
Pass Thru Software Maintenance	24,000	24,000	0.0%	-
Cash Reserve Refund (Requirement)	848,232	657,395	-22.5%	(190,837)
Penalty Assessment Allocation	343,000	153,000	-55.4%	(190,000)
Total Statutory Funding (Equals Total Expenses)	6,793,288	7,162,232	5.4%	368,944

2015 to 2014 RE Division Comparative Budgeted Funding



2015 RE Division Overview

- The FRCC will continue to evaluate the adequacy of its resources and to evaluate efficiencies in its processes in order to continue to carry out its delegated responsibilities.

- The FRCC will continue to align itself and support the ERO Strategic Plan for goals, activities and major activities which include:
  - Support of the RAI with training and implementation for compliance and enforcement staff.
  - Support NERC's plan to develop RSAW's concurrent with Reliability Standards.
  - Work with NERC and the other RE's to provide guidance to registered entities on CIP V5.
  - Work to refine and revise procedures and processes to eliminate duplication, increase operating efficiencies, enhance ERO-wide consistency and to achieve measurable reliability outcomes.

2015 RE Division Risks

- Roll out of RAI may require significantly more staff time than budgeted
- Compliance Software costs may be higher than budgeted due to RAI or unplanned NERC projects
- Additional costs may be incurred to implement recommendations from the FRCC Security Assessment Initiative
- As always, there could be a Compliance Hearing

2015 Proposed RE Division Working Capital Policy

- Working Capital and operating reserve requirements shall be one (1) month of the total annual budget
- A 1.5 million line of credit is available for short term and other risks that may be needed to bridge budget cycles and approved assessments.
- Working Capital shall be utilized to satisfy projected annual cash flow and cash balance requirements.
- Operating reserves shall be utilized to satisfy known contingencies where the specific timing and amount is uncertain.

FRCC Proposed 2015 Total Budget Compared to 2014

	2015 Budget	2014 Budget	$ Change	% Change
Regional Entity Division Expenses W/Fixed Assets	$ 7,162,233	$ 6,793,289	$368,944	5.4%
Member Services Division Expenses W/Fixed Assets	8,391,982	7,455,995	935,987	12.6%
Total Expenses	$15,554,214	$14,249,283	$1,304,931	9.2%
Other Funding – Workshops & Fees	388,459	391,419	2,960	(0.8%)
Cash Reserve (Requirement)/(Surplus)	534,812	1,110,046	575,234	(51.8%)
Penalty Sanctions	153,000	343,000	190,000	(55.4%)
Total FRCC Funding Assessment	$14,477,943	$12,404,818	$2,073,125	16.7%

2015 BP&B Summary

- **Regional Entity**
  - Budget increase of 5.4%
  - 0 new Staff
  - 0.5 increased FTEs

- **Member Services**
  - Budget increase of 12.6%
  - 1 new Staff
  - 1.5 increased FTEs

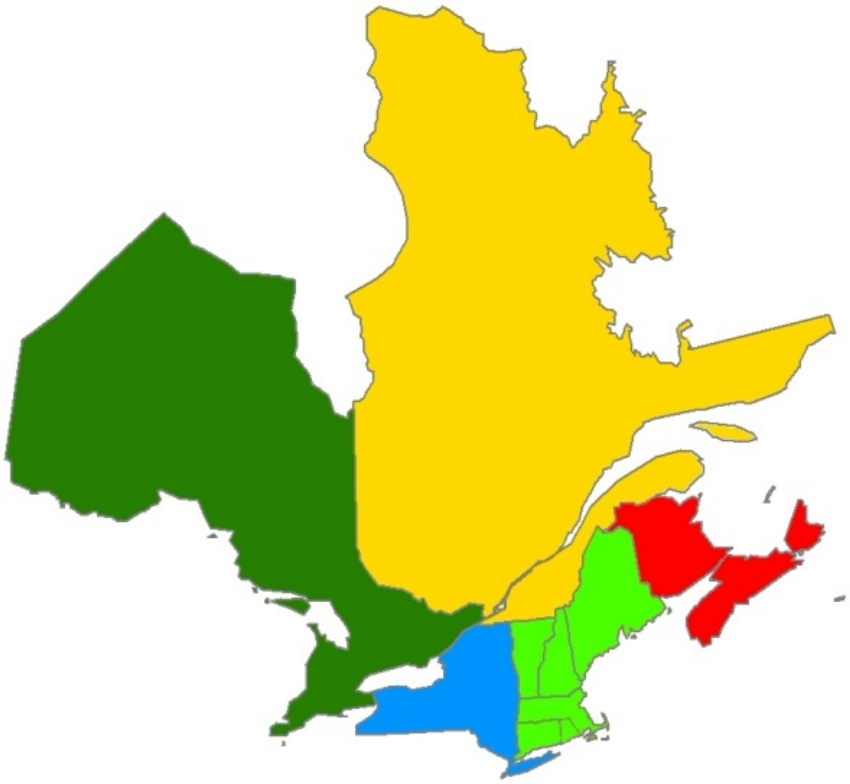
FRCC

QUESTIONS?

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

Northeast Power Coordinating Council, Inc. (NPCC)

Preliminary Draft 2015 Business Plan and Budget



Draft 1
Submitted to NERC
May 14, 2014

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Introduction

Total NPCC Resources (in whole dollars)	2015 Budget	U.S.	Canada	Mexico
Regional Entity Division FTEs	36.86			
Criteria Services Division FTEs	2.14			
Total FTEs	**39.0**			
Regional Entity Division Expenses	$14,758,558			
Criteria Services Division Expenses	$1,139,452			
Total Expenses	**$15,898,011**			
Regional Entity Division Inc(Dec) in Fixed Assets	**$19,981**			
Criteria Services Division Inc(Dec) in Fixed Assets	**($10,011)**			
Total Inc(Dec) in Fixed Assets	**$9,970**			
Regional Entity Division Working Capital Requirement**	**($355,161)**			
Criteria Services Division Working Capital Requirement***	**($94,220)**			
Total Working Capital Requirement	**($449,381)**			
Total Regional Entity Division Funding Requirement	$14,423,378			
Total Criteria Services Division Funding Requirement	$1,035,221			
Total Funding Requirement	**$15,458,599**			
Regional Entity Division Assessments	**$14,078,378**	$XXX,XXX	$XXX,XXX	
Regional Entity Division Assessments Percentage	**100.0%**	XX.X%	XX.X%	
Criteria Services Division Membership Fees	**$760,033**	$XXX,XXX	$XXX,XXX	
Total NPCC Assessments & Membership Fees	**$15,113,599**	$XXX,XXX	$XXX,XXX	
NEL	XX	XX	XX	
NEL %	100%	XX.XX%	XX.XX%	

** Refer to Table B-1 on page 78 in Section B.
*** Refer to the Reserve Analysis on page 97 in Section C.

2015 Overview of Total NPCC Resource Requirements

Due to the international nature of NPCC, the total resource requirements including both Regional Entity division and Criteria Services division are identified above. The individual divisional explanations are contained in subsequent sections.

NPCC proposes to increase its total funding requirement from $14,818,588 to $15,458,599 in 2015, an increase of $640,011 or 4.3%. The proposed 2015 funding requirements will be satisfied by a Regional Entity division assessment of $14,078,378 and Criteria Services division fees of $1,035,221, an overall increase of 3.5% compared to the 2014 total assessments and fees of $14,601,588. NPCC believes that the Region remains an effective provider of Regional Entity and Criteria Services division functions. NPCC's corporate culture centers on consistent delivery of excellent results at a cost that is considerate of the longstanding tradition in the Northeast of affordable and reliable electricity.

Organizational Overview

Northeast Power Coordinating Council, Inc. (NPCC) is a 501(c)(6) not-for-profit corporation in the state of New York responsible for promoting and improving the reliability of the international, interconnected bulk power systems in Northeastern North America through (i) the development of Regional Reliability Standards and compliance assessment and enforcement of continent-wide and Regional Reliability Standards, coordination of system planning, design and operations, and assessment of reliability (collectively, Regional Entity activities), and (ii) the establishment of Regionally-specific criteria, and monitoring and enforcement of compliance

with such criteria (collectively, criteria services activities). NPCC provides the functions and services for Northeastern North America of a cross-border Regional Entity through a Regional Entity division, as well as Regionally-specific criteria services for Northeastern North America through a criteria services division. NPCC's website is www.npcc.org.

The NPCC Region covers nearly 1.2 million square miles and is populated by more than 56 million people. NPCC U.S. includes the six New England states and the state of New York. NPCC Canada includes the provinces of Ontario, Québec and the Maritime provinces of New Brunswick and Nova Scotia. In total, from a net energy for load perspective, NPCC is approximately 45% U.S. and 55% Canadian. With regard to Canada, approximately 70% of Canadian net energy for load is within the NPCC Region.

Effective January 1, 2012, NPCC executed an Amended and Restated Regional Delegation Agreement with the North American Electric Reliability Corporation (NERC) that delegates to NPCC certain responsibilities and authorities of a cross-border Regional Entity as defined by *Section 215* of the Federal Power Act in the U.S. In addition, NPCC has executed Memoranda of Understanding or Agreements with Canadian provincial regulatory and/or governmental authorities in Ontario, Québec, New Brunswick and Nova Scotia.

In this 2015 business plan, NPCC has included activities consistent with NERC initiatives including the implementation of the revised BES definition, risk-based registration, the Reliability Assurance Initiative, and expanded training for compliance auditing.

It is imperative that NPCC maintain its ability to carry out delegated authorities and responsibilities. NPCC has a flat 2015 targeted staffing level of 39 power industry professionals and support personnel. Details of the 2015 business plans and budget for each program area are included in Section A for the Regional Entity division. The 2015 Regional Entity division schedules are shown in Section B. Section C details the 2015 criteria services division business plan and budget.

Membership and Governance

NPCC monitors approximately 300 registered entities and some 602 functions in the Region for compliance with mandatory Reliability Standards. NPCC currently has approximately 78 members. There are two categories of membership, General and Full. The two categories distinguish between Regional Entity delegated services that are provided in support of the U.S. FERC and Canadian provincial MOUs or Agreements with regulatory and/or governmental authorities, and Criteria Services which FERC references as U.S. non-delegated activities.

General Membership is voluntary and is open to any person or entity, including any entity participating in the Registered Ballot Body of the Electric Reliability Organization (ERO) that has an interest in the reliable operation of the Northeastern North American bulk power system. General Members which are also registered entities within the NPCC Region are subject to compliance with Reliability Standards, consistent with their registration, and also receive additional services from the Regional Entity division of NPCC.

Full Membership is available to Members which are already General Members and participate in electricity markets in the Northeast. Independent system operators (ISOs), Regional transmission organizations (RTOs), Transcos and other organizations or entities that perform the Balancing Authority function operating in Northeastern North America are expected to be Full Members of NPCC. The New York State Reliability Council and any other sub-regional

reliability councils which may be formed are also expected to be Full Members. Full Members are subject to compliance with Regionally-specific more stringent reliability criteria for their generation and transmission facilities on which faults or disturbances can have a significant adverse impact outside of the local area and which are identified utilizing a reliability impact-based methodology, in addition to Reliability Standards, and receive additional services from the Criteria Services division of NPCC, which is not funded through the ERO.

Since January 1, 2012 NPCC is governed by a Board of Directors consisting of seven stakeholder voting sectors consisting of a maximum of two directors per sector, an independent sector consisting of two independent directors, an independent Board Chair with voting rights to preclude board deadlocks, and the President and CEO. Within NPCC, no two sectors can control and no one sector can block action. The voting sectors on the NPCC Board of Directors include:

Sector 1) Transmission Owners
Sector 2) Reliability Coordinators
Sector 3) Transmission Dependent Utilities, Distribution Companies, Load Serving Entities
Sector 4) Generator Owners
Sector 5) Marketers, Brokers and Aggregators
Sector 6) Regulators
Sector 7) Sub-Regional Reliability Councils, Customers, other Regional Entities and Interested Entities
Sector 8) Independent

A Finance and Audit Committee (FAC), a Pension Committee (PC), a Corporate Governance and Nominating Committee (CGNC), and a Management Development and Compensation Committee (MDCC) advise the Board on finance, governance, compensation and human resource matters. The Board endorses a non-employee, Certified Public Accountant for election by the NPCC Members as Treasurer of the corporation. The Treasurer chairs the FAC and works with the Chief Operating Officer who provides oversight of the finances of the corporation. The Treasurer reports to the Board on the corporation's financial position, on FAC activities, on tax code requirements, and on independent annual audit results and accounting practices.

The Regional Standards Committee (RSC), the Compliance Committee (CC), the Reliability Coordinating Committee (RCC), and the Public Information Committee, consistent with their approved scopes, are responsible for various reliability issues. The RSC, CC and RCC also provide technical policy recommendations to the Board. All General and Full Members are eligible for representation on the technical committees.

Industry technical experts from within the membership provide valuable input to the Board through various working groups and task forces as well as the committees. The *Amended and Restated Bylaws* establishes NPCC's independence from users, owners and operators of the bulk power system through the enhanced governance structure while providing fair stakeholder representation in the election of the Board of Directors and officers. The members, from each of the seven stakeholder voting sectors, vote to elect directors in their respective sector. The *Amended and Restated Bylaws* establish criteria for board service for both stakeholder and independent directors. Independent Directors are drawn from diverse backgrounds and possess a broad range of industry expertise, perspectives, experiences, skill sets and knowledge to contribute to the effective functioning of a hybrid board structure.

Compliance and enforcement activities are carried out by the NPCC compliance staff and are independent of all users, owners and operators of the international bulk electric system. Compliance activities are governed in the United States by the *Amended and Restated Regional Delegation Agreement* between NERC and NPCC, delegating portions of NERC's authority as the ERO to NPCC. NPCC compliance activities in Canada are governed by an individual provincial Memorandum of Understanding (MOU) or Agreements with each province providing the unique parameters for compliance and enforcement activities for each of the provinces. A MOU between the Independent Electricity System Operator in Ontario (IESO), NERC and NPCC establishes roles and responsibilities with regard to that province. NPCC, NERC and the New Brunswick Energy and Utilities Board are parties to a MOU that sets forth reliability activities for New Brunswick. The Régie de l'énergie, NERC and NPCC executed an Agreement regarding the development of electric power transmission Reliability Standards and a program for the monitoring of the application of these standards for Québec. NPCC, NERC and Nova Scotia executed a MOU that sets forth the mutual understanding of the parties in relation to the approval and implementation of NERC Reliability Standards and NPCC Regional reliability criteria for the province of Nova Scotia.

International Foundation

The Regional Entity functions and services differ according to particular regulatory backstop:

a) U.S. Foundation

The Federal Energy Regulatory Commission (FERC) certified NERC as the Electric Reliability Organization (ERO) on July 20, 2006. The ERO is responsible for developing and enforcing reliability standards within the United States. In executing part of its responsibilities, NERC delegates authority to the Regional Entities to perform certain functions through delegation agreements. Ensuring the reliability of the bulk power system in the state of New York and the six New England States was delegated from NERC to NPCC through the Amended and Restated Regional Delegation Agreement.

b) Ontario

On February 5, 2010, NERC, NPCC and the IESO amended and restated their earlier MOU, dated November 29, 2006, setting forth their mutual understanding as regards NERC's and NPCC's status in Ontario with respect to standard and criteria development, compliance enforcement, and other related matters. The IESO, whose statutory responsibilities include making and enforcing reliability standards, and making and enforcing Ontario market rules that govern the IESO-controlled grid and the wholesale electricity market, was established April 1, 1999 as the Independent Electricity Market Operator in Ontario under the *Electricity Act, 1998* (Ontario). The IESO is subject to the regulatory oversight of the Ontario Energy Board (OEB).

Among other things, the MOU recognizes that NERC and NPCC are standards authorities under the *Electricity Act, 1998* (Ontario). Additionally, under the authority of that same legislation, and as memorialized in the MOU, the NERC reliability standards and NPCC reliability criteria have effect in Ontario. However a 2008 amendment to the Electricity Act, 1998 (Ontario) allows the OEB to review these standards and criteria and issue orders preventing their implementation and remanding them back to NERC and NPCC.

The IESO is subject to compliance monitoring and enforcement by NPCC. The IESO is also subject to compliance monitoring and enforcement of the Ontario market rules by the IESO's Market Assessment and Compliance Division (MACD) that operates at arm's length from the IESO's business units. The MOU notes that where MACD, NERC, and NPCC engage in

investigations pursuant to their respective mandates regarding compliance, MACD can request to take the lead. Moreover, of the three, MACD is the only entity that can assess financial penalties for any Ontario market participant's or the IESO's non-compliance with Ontario market rules, which includes non-compliance with NERC standards and NPCC criteria.

The MOU provides for a peer review process to promote the common compliance and enforcement objectives of NERC/NPCC and MACD. From the perspective of NPCC and NERC, this process, in part, is meant to assure registered entities outside of Ontario that the MACD program is rigorous, thorough and reliable.

The IESO is subject to NPCC assessments of compliance, including audits, as well as NPCC remedial action directives to correct non-compliance. In the event that the IESO disagrees with NPCC's finding of a violation or associated assessment of sanctions in connection with standards and criteria, the IESO has a right to a compliance hearing with NPCC.

c) Québec

The Régie de l'énergie, NERC and NPCC are parties to the May 8, 2009 *Agreement on the Development of Electric Power Transmission Reliability Standards and of Procedures and a Program for the Monitoring of the Application of These Standards for Québec* (the Agreement). Under the terms of the Agreement, the Régie de l'énergie , which is charged with ensuring the reliability of the electric transmission in Québec, retained NPCC and NERC as experts to develop reliability standards and monitoring program procedures for the Province.

The Régie de l'énergie is a public body established by the *Act respecting the Régie de l'énergie* (the Act). Pursuant to its authority under the Act, the Régie de l'énergie, through a series of decisions in 2007, designated Hydro-Québec TransÉnergie (HQTE) as the Reliability Coordinator for Québec. In accordance with its mandate and as recognized in the Agreement, it is this entity that is responsible for the filing with the Régie de l'énergie for approval of reliability standards in Québec. HQTE has filed for the approval of certain reliability standards and the Régie de l'énergie has begun the proceedings required to make such reliability standards mandatory in Québec.

The Agreement contemplates the execution of a second agreement that will detail the mandates granted by the Régie de l'énergie to NPCC and NERC with respect to the implementation of the procedures and program for the monitoring of the application of electric power transmission Reliability Standards in Québec and the provision of opinions and recommendations to the Régie in this regard. The second agreement is currently being negotiated by the Régie de l'énergie, NPCC and NERC. The intent, once all the appropriate authorizations are in place, is that NPCC and NERC will act as the Régie's agents in all compliance monitoring and enforcement activities through the implementation of a Québec specific compliance monitoring and enforcement program.

Currently, as there are only a limited number of mandatory standards that have come into effect, and as the second agreement and all the appropriate authorizations covering compliance monitoring and enforcement arrangements are not in place, there has been limited mandatory compliance activity under the formal Québec regime. However, the Hydro-Québec companies, including Hydro-Québec TransÉnergie and Hydro-Québec Production have been subject to voluntarily compliance monitoring, including comprehensive audits by NPCC. Additionally, NPCC has and continues to proceed with its reliability assurance activities within Québec,

including but not limited to events analysis, Reliability Assessment and Performance Analysis and compliance investigations, consistent with the NPCC *Amended and Restated Bylaws*.

d) New Brunswick

The New Brunswick Energy and Utilities Board ("EUB") and NPCC entered into an Agreement dated October 1, 2013, whereby NPCC provides services for the EUB. The EUB is a not-for-profit corporation which was established on October 1, 2004 under the Electricity Act (NB) and charged with developing and administering the wholesale electricity market and maintaining reliability of the integrated power system in New Brunswick.

Effective October 1, 2013, the Electricity Act (NB) and implementing regulations (together, "NB Electricity Act") amended how Reliability Standards are approved, monitored, and enforced in the province of New Brunswick. The NB Electricity Act designates NPCC as a compliance body and NERC as a standards body within the meaning of the NB Electricity Act. The October 1, 2013 Agreement between NPCC and the EUB is intended to be the preliminary step with respect to the implementation of the NB Electricity Act.

With respect to the approval of reliability standards, the NB Electricity Act provides that all of the NERC Reliability Standards that were effective in New Brunswick prior to October 1, 2013 continue to be effective in New Brunswick after October 1, 2013. Additionally, the New Brunswick Power Corporation (formed from several amalgamating corporations) ("NBPC") is required to file for approval, modification, or retirement of NERC Reliability Standards 60 days after a NERC Reliability Standard is approved, modified, or retired by the Federal Energy Regulatory Commission ("FERC"). The EUB rules on the filed Reliability Standard after considering (a) the potential impact on the reliability of the bulk power system, (b) the potential cost and benefits (c) the public interest, and (d) any other factors that the NBUEB considers relevant. The Electricity Act requires the NBEUB to notify NPCC and NERC of an application by the NBPC with respect to reliability standards and provide for a 60 day comment period. The NBEUB is required to approve the reliability standards if there are not substantive modifications proposed from the FERC approved NERC Reliability Standard and there were no substantive comments filed. Amendments to the reliability standard to make them compatible with New Brunswick or Canadian law are considered non-substantive. The approval of reliability standards may be subject to a hearing for several reasons, including substantive comments from NPCC or NERC.

With respect to the monitoring and enforcement of the Reliability Standards in New Brunswick, the NB Electricity Act requires NPCC to identify entities that must register with the EUB in the New Brunswick specific registry. Additionally, NPCC is required to carry out the compliance monitoring and assessment for the EUB and assist and advise the enforcement for the EUB, including financial penalties. NPCC is also permitted to carry out or exercise any power in the implementing regulations that is specific to the EUB. Additionally, NPCC has the powers of an inspector, which permits NPCC to audit and spot check entities within New Brunswick.

e) Nova Scotia

Nova Scotia Power Incorporated (NSPI), NPCC and NERC are parties to a May 11, 2010 Memorandum of Understanding regarding the approval and implementation of mandatory NERC reliability standards and NPCC Regional reliability criteria. Pursuant to the MOU's terms, NERC and NPCC filed standards and criteria with the Nova Scotia Utility and Review Board (NSUARB) for approval on June 30, 2010 and June 29, 2010, respectively. A decision from the NSUARB on both NERC and NPCC filings was rendered on July 20, 2011. Hence, the

standards and criteria are mandatory in Nova Scotia and NSPI will be subject to the NERC compliance monitoring and enforcement program, as implemented by NPCC.

NPCC will conduct compliance activities with respect to the standards and then forward any non-compliance information and recommendations to the NSUARB for use in enforcement proceedings. Enforcement will be administered by the NSUARB which will, among other things, determine whether a violation has occurred and, if so, what remedial measures or non-monetary penalties should be imposed.

Regional Entity Division Functional Scope

NPCC's Regional Entity division functions in support of the ERO include:

- Active participation in the development of North American Reliability Standards for the bulk electric system, and as needed development of Reliability Standards applicable within the NPCC cross-border Regional Entity
- Monitoring and enforcement of approved Reliability Standards, including the registration of responsible entities, and as needed certification of such entities
- Assessment of the present and future reliability of the bulk power system
- Operational coordination and situation awareness support
- Event analysis and identifying lessons learned to improve reliability
- Effective training and education of reliability personnel
- Promoting the protection of critical electric infrastructure

In recognition of the delegated compliance role of Regional Entities as an important means to enhancing reliability, NPCC has designated a significant percentage of its staff resources to compliance monitoring and enforcement. NPCC has also developed and deployed a robust set of online tools for gathering data, analysis, and tracking of compliance information to support its ability to carry out its responsibilities in a cost effective manner.

NPCC has organized the remaining staff into program areas consistent with EPAct 2005 to address the other functions listed above. These experts in operations, planning and reliability analysis assist registered entities in assessing and improving reliability. It is in support of these areas that NPCC engages the majority of industry experts on its technical committees.

2015 Key Assumptions and 2015 Goals and Key Deliverables

NERC and the eight Regional Entities collaborated in the development of a common operating model with complementary roles and responsibilities, an ERO Enterprise Strategic Plan, and a set of business planning assumptions, goals, metrics and key deliverables for the 2014 through 2017 period. The results from that collaboration are included as a set of Shared Business Plan and Budget Assumptions that will be contained in Exhibit A to the NERC 2015 Business Plan and Budget and may be referenced by the users of this document. In each of the following program area sections footnotes are used to reference the specific ERO Enterprise Goals that NPCC's activities support.

2015 Overview of Regional Entity Division Cost Impacts

NPCC proposes to increase its Regional Entity division funding requirement from $13,828,880 to $14,423,378 in 2015, an increase of $594,498 or 4.3%. The proposed Regional Entity division assessment of $14,078,378 to support the budget is an increase of 3.4% compared to the 2014 assessment of $13,611,880.

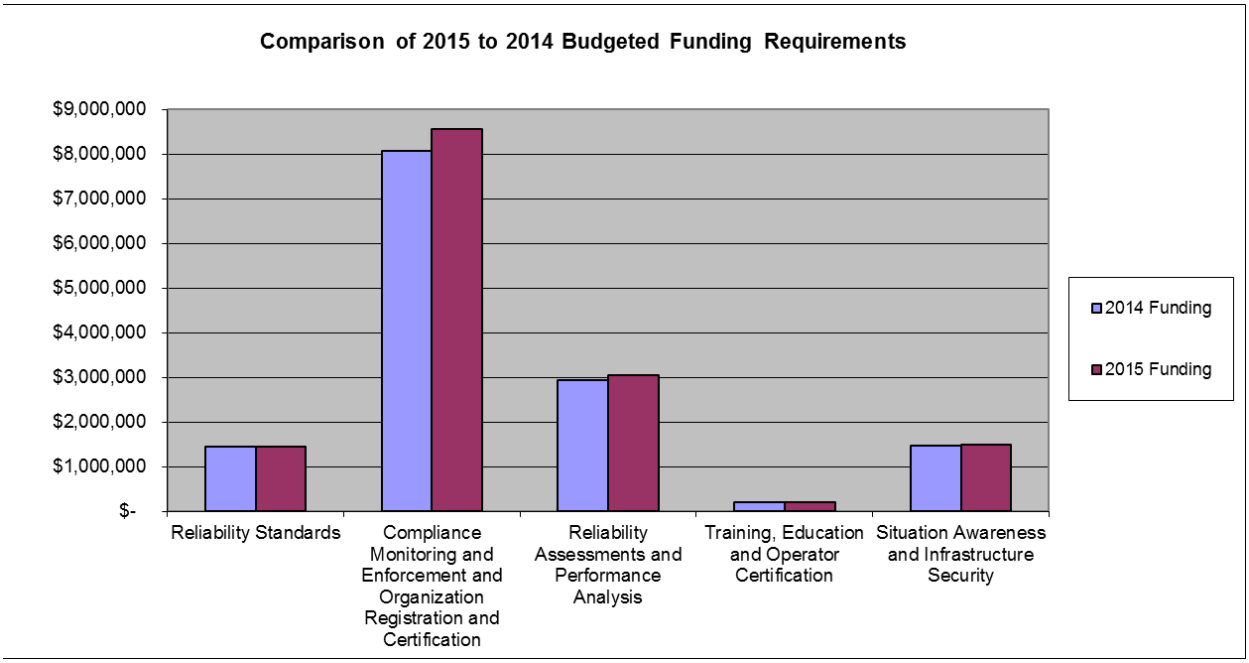
2014 Projections

Current year projections are taken into consideration in development of the budget. Expenses are currently projected to be on budget or slightly under budget in all areas. 2014 Projections reflect expectations based on the first quarter statement of activities. It is anticipated that projections could change throughout 2014 and would be reflected in each subsequent quarter's statement of activities.

Summary by Program

Program	Budget 2014	Projection 2014	Budget 2015	Variance 2015 Budget v 2014 Budget	Variance %
Reliability Standards	$ 1,447,330	$ 1,447,330	$ 1,456,129	$ 8,799	0.6%
Compliance Monitoring and Enforcement and Organization Registration and Certification	$ 8,079,371	$ 8,079,371	$ 8,568,145	$ 488,774	6.0%
Reliability Assessments and Performance Analysis	$ 2,942,339	$ 2,942,339	$ 3,053,923	$ 111,585	3.8%
Training, Education and Operator Certification	$ 195,855	$ 195,855	$ 199,010	$ 3,154	1.6%
Situation Awareness and Infrastructure Security	$ 1,464,111	$ 1,464,111	$ 1,501,332	$ 37,221	2.5%
Total	$ 14,129,006	$ 14,129,006	$ 14,778,539	$ 649,533	4.6%

This chart does not include allocation of working capital requirements among the Program Areas.



This chart does not include allocation of working capital requirements among the Program Areas.

Personnel Analysis

Total FTE's by Program Area	Budget 2014	Projection 2014	Direct FTEs 2015 Budget	Shared FTEs[1] 2015 Budget	Total FTEs 2015 Budget	Change from 2014 Budget
REGIONAL ENTITY DIVISION						
Operational Programs						
Reliability Standards	2.93	2.93	2.00	0.93	2.93	0.00
Compliance Monitoring and Enforcement and Organization Registration and Certification	16.00	16.00	16.00	0.00	16.00	0.00
Training, Education, and Operator Certification	0.10	0.10	0.10	0.00	0.10	0.00
Reliability Assessment and Performance Analysis	5.83	5.83	4.90	0.93	5.83	0.00
Situation Awareness and Infrastructure Security	3.00	3.00	3.00	0.00	3.00	0.00
Total FTEs Operational Programs	**27.86**	**27.86**	**26.00**	**1.86**	**27.86**	**0.00**
Administrative Programs						
Technical Committees and Member Forums	0.50	0.50	0.50	0.00	0.50	0.00
General and Administrative	2.50	2.50	2.50	0.00	2.50	0.00
Information Technology	3.00	3.00	3.00	0.00	3.00	0.00
Legal and Regulatory	1.00	1.00	1.00	0.00	1.00	0.00
Human Resources	1.00	1.00	1.00	0.00	1.00	0.00
Accounting and Finance	1.00	1.00	1.00	0.00	1.00	0.00
Total FTEs Administrative Programs	**9.00**	**9.00**	**9.00**	**0.00**	**9.00**	**0.00**
Total FTEs	**36.86**	**36.86**	**35.00**	**1.86**	**36.86**	**0.00**

[1]A shared FTE is defined as an employee who performs both Regional Entity and Criteria Services division functions.

2014 Budget and Projection and 2015 Budget Comparisons

Statement of Activities and Capital Expenditures
2014 Budget & Projection, and 2015 Budget

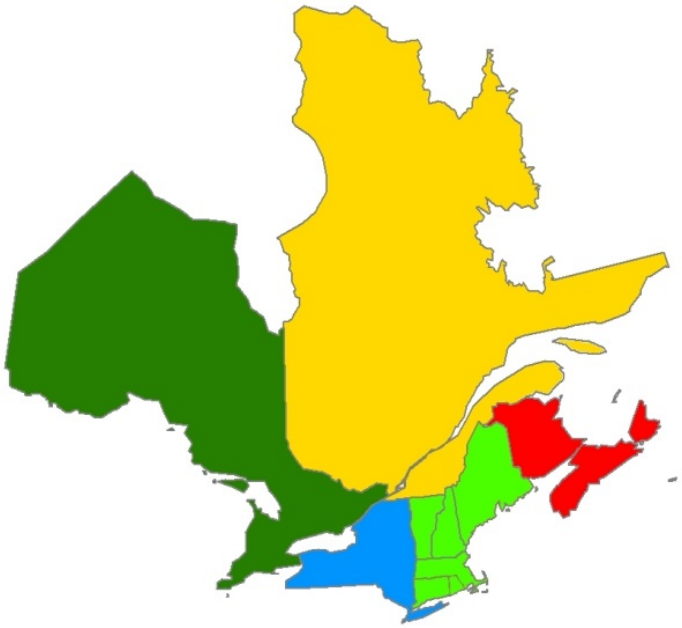
REGIONAL ENTITY DIVISION

		2014 Budget	2014 Projection	Variance[2] 2014 Projection v 2014 Budget Over(Under)	2015 Budget	Variance 2015 Budget v 2014 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ 13,611,880	$ 13,611,880	$ -	$ 14,078,378	$ 466,498
	Penalty Sanctions[1]	153,000	153,000	-	281,000	128,000
Total ERO Funding		**$ 13,764,880**	**$ 13,764,880**	**$ -**	**$ 14,359,378**	**$ 594,498**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops	64,000	64,000	-	64,000	-
	Interest	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Funding (A)		**$ 13,828,880**	**$ 13,828,880**	**$ -**	**$ 14,423,378**	**$ 594,498**
Expenses						
Personnel Expenses						
	Salaries	$ 5,911,227	$ 5,911,227	$ -	$ 6,195,425	$ 284,198
	Payroll Taxes	384,311	384,311	-	387,209	2,898
	Benefits	1,430,261	1,430,261	-	1,256,595	(173,666)
	Retirement Costs	1,124,361	1,124,361	-	1,090,013	(34,348)
Total Personnel Expenses		**$ 8,850,160**	**$ 8,850,160**	**$ -**	**$ 8,929,241**	**$ 79,081**
Meeting Expenses						
	Meetings	$ 365,000	$ 365,000	$ -	$ 365,000	$ -
	Travel	890,000	890,000	-	890,000	-
	Conference Calls	77,000	77,000	-	45,000	(32,000)
Total Meeting Expenses		**$ 1,332,000**	**$ 1,332,000**	**$ -**	**$ 1,300,000**	**$ (32,000)**
Operating Expenses						
	Consultants & Contracts	$ 1,924,433	$ 1,924,433	$ -	$ 2,342,000	$ 417,567
	Office Rent	737,272	737,272	-	751,500	14,228
	Office Costs	536,500	536,500	-	578,700	42,200
	Professional Services	966,500	966,500	-	1,025,000	58,500
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	80,000	80,000	-	40,000	(40,000)
	Depreciation	250,000	250,000	-	202,019	(47,981)
Total Operating Expenses		**$ 4,494,705**	**$ 4,494,705**	**$ -**	**$ 4,939,219**	**$ 444,514**
	Total Direct Expenses	**$ 14,676,865**	**$ 14,676,865**	**$ -**	**$ 15,168,460**	**$ 491,595**
Indirect Expenses		**$ (405,859)**	**$ (405,859)**	**$ -**	**$ (409,902)**	**$ (4,043)**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 14,271,006**	**$ 14,271,006**	**$ -**	**$ 14,758,558**	**$ 487,552**
Change in Assets		**$ (442,126)**	**$ (442,126)**	**$ -**	**$ (335,180)**	**$ 106,946**
Fixed Assets						
	Depreciation	$ (250,000)	$ (250,000)	$ -	$ (202,019)	$ 47,981
	Computer & Software CapEx	108,000	108,000	-	222,000	114,000
	Furniture & Fixtures CapEx	-	-	-	-	-
	Equipment CapEx	-	-	-	-	-
	Leasehold Improvements	-	-	-	-	-
	Allocation of Fixed Assets	(0)	(0)	-	(0)	-
Inc(Dec) in Fixed Assets (C)		**(142,000)**	**(142,000)**	**-**	**19,981**	**161,981**
TOTAL BUDGET (=B+C)		**$ 14,129,006**	**$ 14,129,006**	**$ -**	**$ 14,778,539**	**$ 649,533**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ (300,126)**	**$ (300,126)**	**$ -**	**$ (355,161)**	**$ (55,035)**

[1] $281,000 of penalty sanctions collected to date and prior to June 30, 2014.

[2] 2014 Projections reflect expectations based on the 1st quarter statement of activities. It is anticipated that projections could change throughout 2014 and would be reflected in each subsequent quarter's statement of activities.

Section A – Regional Entity Division
2015 Business Plan and Budget



Section A — 2015 Business Plan

Reliability Standards Program

Reliability Standards Program Resources (in whole dollars)	2014 Budget	2015 Budget	Increase (Decrease)
Total FTEs	2.93	2.93	0.00
Direct Expenses	$917,936	$905,638	($12,299)
Indirect Expenses	$555,686	$561,221	$5,535
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	($26,292)	($10,729)	$15,563
Total Funding Requirement	$1,447,330	$1,456,129	$8,799

Program Scope and Functional Description

The NPCC Reliability Standards program operates in accordance with NPCC's filed and approved Delegation Agreement "Exhibit C", and NERC Rules of Procedure Section 300. The program supports the ERO standards program area roles and responsibilities by providing supporting activities for the development of clear, concise, sustainable, high quality and technically sound mandatory "results based" reliability standards which provide for an adequate level of reliability in a timely and efficient manner. The primary objective of NPCC's program area is to support the development of ERO standards which establish threshold requirements for ensuring the bulk electric system is planned, operated, and maintained in a manner that minimizes risks of cascading failures, avoids damage to major equipment, is responsive to risks, or limits interruptions of bulk power supply. At a Regional level, the program develops Regional Reliability Standards and ensures that Regional reliability criteria, contained in the form of Directories, are not inconsistent with any applicable NERC and Regional Reliability Standards. The NPCC Reliability Standards program also supports and participates in the development, revision, and maintenance of NERC Reliability Standards, initiates new regional or continent wide reliability standards when necessary, and provides a forum for the comprehensive review and improvement of existing and developing standards.

The NPCC Reliability Standards Program Area supports the reliability of the bulk electric system by:

- Facilitating active participation of NPCC Regional industry stakeholders in all NERC Reliability Standards activities to promote the development of results based, cost effective quality standards in a timely and efficient manner.
- Promote awareness by holding workshops and conducting Regional Standards Committee meetings to inform and educate stakeholders.
- Internally and informally training staff for the new and developing standards through meetings.
- Regional coordination activities with Standards Program Areas from other Regions.

- Development and maintenance of Regional Standards as necessary to address Regional reliability related issues or risks and ensure those standards are not inconsistent with the NERC continent wide standards. These Regional standards contain requirements that are more stringent, add specificity to or augment the NERC Continent-wide standards.
- NPCC maintains and abides by the NPCC Regional Standards Processes Manual assuring compliance with all FERC filed documents with respect to standards development.

Funding Drivers and Reliability Benefits

- Expanded Scope of Standards activities
    - Utilize NPCC RSC, Task Forces and Working Groups to comment on developing NERC Standards to ensure they are results based and directionally consistent with the Independent Experts Review Panel Report (IERP)[1]
    - Develop process for ensuring lessons learned from Event Analysis are evaluated for any gaps in standards or criteria[2]
    - Responding to increasing amount of FERC Rulings, NOPRs, preliminary staff assessments, and FERC issued Directives[3]
    - Providing support for increased standard development activities as outlined in the NERC 2014-2016 Reliability Standards Development Plan and assuming an active role in the newly formed NERC Project Management Oversight Subcommittee ("PMOS")
    - Participating in informal activities of standards development to promote consensus early in project development and provide technical guidance
    - Providing a forum for all NPCC representatives on the NERC drafting teams
    - Actively coordinating and reviewing Reliability Standards Audit Worksheets (RSAW) for correctness
    - Provide NPCC Regional point of contact for the new Reliability Issues Steering Committee ("RISC") to provide emerging and existing BES reliability related risks and potential gaps in the existing NERC standards
- Increased Number of Standards Projects
    - Active NERC Projects in the standards area are also expected to increase to address FERC outstanding directives.
    - The concept of informal development was introduced in 2013 and will be expanded to include more standards development projects in 2015 requiring more technical support, participation, and facilitation.
    - NERC has developed procedures and processes to allow it to revise standards in a more expeditious manner that may need clarification or address some deficiency.
    - NPCC is assisting with the Project Management Oversight Subcommittee (PMOS) which is responsible for managing the development of NERC standards projects and tracking Paragraph 81 Phase 2 retirement candidates

[1] In support of ERO Goal 1a Develop Standards which are clear, responsive to reliability and security risks, practical to implement, and cost-effective

[2] In support of ERO Goal 1aDevelop Standards which are clear, responsive to reliability and security risks, practical to implement, and cost-effective

[3] In support of ERO Goal 1a Develop Standards which are clear, responsive to reliability and security risks, practical to implement, and cost-effective

  - Promote and assist with the Cost Effective Analysis Process ("CEAP") to ensure standards have the most cost effective requirements which meet the reliability objectives of standards under development[4]

- Further resources required to evaluate the standards from a "cost benefit" and also a "cost effectiveness" perspective will be required.
- NERC Reliability Standards will continue to require Violation Risk Factors (VRFs) to be developed and NERC is reviewing additional levels of VRF and development of a Sanction Matrix which is envisioned to replace the Violation Severity Levels (VSLs).
- Expanded efforts to educate and inform stakeholders in the areas of NERC and NPCC Regional Standards through NPCC Workshops and with anticipated additional forums such as increases in the amount of Internet based meetings and technical conferences. [5]

2015 Key Assumptions

- Facilitate stakeholder review, comment on, and develop ballot recommendations or list of Regional issues, for all NERC Reliability Standards Projects under informal or formal development or revision prior to the end of ballots
  - NERC and NPCC benefit from NPCC's Regional coordination consisting of a broad stakeholder review process and development of consensus recommendations to assure proposed standards will support international reliability and provide appropriate reliability objectives for the Continent-wide standards
  - Coordinate a comprehensive review of the results based standards initiative processes and standards being implemented
  - Conduct and obtain training for performing Quality Reviews of standards at both the Regional level and to assist the ERO with analysis of the continent wide standards
  - Coordinate the review of all Reliability Standards Audit Worksheets during their postings for comment for potential expansion of their associated standard's requirements
  - Refine the NPCC triage process to assess posted standards and related material to ensure it is properly routed to and addressed by the appropriate NPCC technical or process resources.
- Participate in the stakeholder efforts to develop Standards Authorization Requests (SARs) and Regional SARs to further improve standards in response to any potential inadequacies in reliability or to improve standards
- Monitor and participate in the drafting of key NERC Reliability Standards-CIP, Protections Systems, Balancing Control Performance, and Frequency Response, etc.
  - The NPCC monitoring of the development of standards helps to ensure reliability requirements that are clear, measureable, and enforceable and support international reliability in the Northeast
- Continue with the development and maintenance of a set of NPCC Phase II Directories not inconsistent with the NERC Reliability Standards which clearly delineate the more stringent NPCC criteria requirements

[4] In support of ERO Goal 1a Develop Standards which are clear, responsive to reliability and security risks, practical to implement, and cost-effective

[5] In support of ERO Goal 1a Develop Standards which are clear, responsive to reliability and security risks, practical to implement, and cost-effective

  - The combination of North American and Regional Reliability Standards with the more-stringent NPCC Regional criteria provides for consistency and operational clarity while providing robust defense in–depth, results based, standards to ensure BES reliability
  - Ensure no redundancies exist between the criteria found in the NPCC Directories and the ERO standards
  - Retire Directories that have been overtaken by improved NERC standards
  - Continually file the more stringent requirements with the New York State Department of Public Service and Canadian Provinces as applicable
- Review reliability requirements of ERO and NPCC Regional Standards, NPCC Criteria and ensure consistency, remove redundancies, adopt Functional Model language and ensure requirements are "results based"
  - The unambiguous assignment of reliability requirements to specific functional entities benefits international reliability
  - Participate in the continuing refinement of the Functional Model to capture evolving issues essential to reliability and new objectives in the industry, i.e. demand resource operator, planning functions, new activities yet to be identified such as those associated with Smart Grid, "Synchro-Phasor" technology, etc.
  - Participate in the continual improvement of the NERC standards development processes and initiatives such as the CEAP, PMOS and Single Portal Project.
  - Contribute to the improvement of process related to NERC providing interpretations.
- Review all FERC orders and Provincial regulations as they relate to the standards, their revision and adoption
  - Northeast reliability benefits from careful analyses of governmental orders or actions adopting standards to assure consistency in interpretation
  - Review rulings that are issued and all FERC Directives for potential reliability related issues
  - Conduct and support Regulatory/Governmental Provincial filings on a periodic basis based on individual Provincial Laws and requirements outlined in the Memorandum of Understandings for each Province.
- Enhance NPCC standards website pages to provide uniform and clear information to the stakeholders while also providing the historical and archived information to support NERC and FERC approvals and expanding requirements

2015 Goals and Key Deliverables

The Reliability Standards program goals and objectives for 2015 are grouped into seven categories:

1) Participate in the ERO Results-Based Standards Development

- Participate in the development and revision of the NERC three year work plan through review, commenting and drafting activities
- Participate in the Standards Committee Strategic initiatives to develop results based standards that will provide a defense in depth, complete the standards due for 5 year review, and address all existing and outstanding FERC Directives.
- Support the implementation of the NERC Board of Trustees ("BOT") resolutions specifically supporting the timeliness, cost effectiveness, timely development, and quality of new standards

- Coordinate the development of ERO Reliability Standards within NERC's three-year standards work plan with the emphasis placed on reducing the amount of new FERC Directives issues by closer coordination with the Commission staff
- Conduct thorough reviews of all NERC standards being developed or revised and coordinate comments for Northeastern North America driving consensus to the extent possible
- Facilitate and enhance the NERC Cost Effective Analysis Procedure both within NPCC throughout the industry
- Conduct thorough reviews of all Industry requested NERC Formal Interpretations of standards and develop and promote the NERC Informal Guidance Process, a comprehensive process to deal with all standards related questions, e.g. Single Portal
- NPCC staff along with NPCC solicited Regional drafting team volunteers, will participate in the drafting of all ERO standards affecting or potentially affecting reliability in the Eastern Interconnection and provide support for review and development of comments and propose improvements with specific emphasis on CIP
- NPCC and its members will review and coordinate potential comment on FERC preliminary staff assessments as appropriate
- Participate in ballots for ERO standards and provide consensus recommendations to the NPCC Members of the NERC Registered Ballot Body or provide a list of issues to allow the Members to cast a ballot based on Regional concerns prior to the end of the ballots
- Review and develop issues on FERC Notice of Proposed Rulemakings for any and all standards related issues as appropriate
- Coordinate and evaluate proposed standards utilizing NPCC's Regional technical task forces, working groups and committees
- Educate and notify stakeholders and regulators about issues related to standards development through various means such as webinars and workshops
- Provide outreach to industry trade groups to educate and drive consensus such as the North American Generator Forum and North American Transmission Forum
- Provide a forum for NPCC review of proposed and posted documents from the NERC Critical Infrastructure Protection Committee (CIPC) and NPCC Task Force on Infrastructure Security and Technology (TFIST)
- Provide support to NERC's strategy in the prioritization, identification, scheduling and development of NERC directed Regional Reliability Standards
- Participate in NERC's Standards Committee standards prioritization process, to identify immediate standards needs and prioritization based on need
- Participate in the NERC RISC by providing a Regional point of contact for all potential reliability related risks and gaps within the Northeast or as noted by NPCC stakeholders
- Participate in and provide support to critical standards, such as UVLS, Voltage and Reactive Control, Real Time Tools, Frequency Response, etc.
- Identify and initiate Regional Variances to the NERC Reliability Standards as soon as possible, allowing incorporation into the continent wide standard at its inception
- Identify potential drivers for standards revisions based on revisions to the BES to a bright line criteria and any document revisions required as a result of consideration of the "Exception Process".
- Support additional standards workload from further economic stimulus, i.e. standards on integrating variable generation resources or EHV backbone, Smart Grid, Electric Vehicles or "Synchro-Phasor" projects as necessary

- Provide continued input and leadership to NERC, based on NPCC experiences, regarding strategy for developing cost effectiveness analysis for standards and support activities to enhance this to identify "benefits" for the draft standards.
- Provide support and assistance to the ERO for conducting Quality Review activities on NERC continent-wide standards as possible
- Continually file the NPCC Directories with the Canadian Provincial Regulatory Authorities within the NPCC "footprint", on an as needed basis, as the directories are developed and revised and as the Provinces establish procedures and agreements with NPCC.
- Continue to develop new and innovative processes to better utilize the limited internal and external resources in the Region to enable sufficient technical review of posted standards and related materials
- Support the ERO and the relationships with FERC and the provincial governmental authorities for standards development activities as necessary to accomplish the ERO goals and objectives
- Support the development of system protection and control, communication, transmission operation standards and other critical standards efforts.

2) Regional Standards Development

- NPCC does not anticipate developing further Regional Standards but reserves the right to do so if a reliability issue exists that is not appropriate for Continent-wide development and also will perform clarifications as needed to existing approved Regional Standards.
- Draft any additional standard NERC directs NPCC to develop to meet an urgent reliability related needs, i.e. Geomagnetic disturbance system hardening
- Accomplish all directives of ERO and governmental and/or regulatory authorities with regard to Regional Standards development and procedures
- Adhere to and surpass, where practical, the 2014-2016 NERC Work plan milestones as they pertain to targets for the Regional Standards
- Respond to any FERC Directives that may arise as a result of the filing of NPCC's Regional Standards with the FERC or any Provincial "directives" that may be issued by the Canadian Regulatory Authorities

3) Standards Improvement

- Achieve NPCC reliability goals and objectives by initiating, participating in, and efficiently completing standards related activities
- Leverage internet and web based tools functionality to ensure inter-Regional consistency and quality of Regional Reliability Standards
- Establish long-term strategy for standards improvement and initiate implementation
- Continually identify additional future Regional Standard opportunities if Continent-wide standards are not an appropriate solution
- Ensure the topics addressed by the Reliability Standards parallel changing industry needs
- Participate in reliability metrics activities to identify potential measures for benchmarking of reliability to determine if an adequate level of reliability is being achieved
- Support and develop cost-benefit analysis activities to determine if any potential incremental increases in costs of implementing a standard have sufficient enough reliability benefit to implement that standard

4) Coordination of review of RSAWs

- Develop a process to review the RSAWs consisting of subject matter experts to determine if the RSAWs are technically representative of the standard's requirements and also to review the evidence suggested in the RSAW for satisfactory compliance assessment
- The Regional Standards Committee ("RSC") will oversee and provide the results of the coordination to the appropriate NERC SDT charged with development of the RSAW

5) Business Practices Interface

- Coordinate the review of standards through NPCC RSC, staff, and other members participating in activities of the North American Electric Standards Review Board (NAESB)
- Identify potential market related issues for Regional Standards through NPCC RSC coordination and reviews

6) Opportunities for Process Improvement

- Identify efficiencies for a coordinated NERC standards development process and NPCC Regional Standards Development Procedure and recommend revisions as applicable to either process
- Refine the NERC and NPCC CEAP s to evaluate the costs and effectiveness of proposed new and revised reliability standards to achieve an adequate level of reliability and a steady state set of standards
- Participate in any potential revision and redrafting of the NERC Standards Development Process to consider expedited standards development and cost effectiveness analysis and maintaining the ANSI Accreditation for standards development
- Participate in the enhancement of the Single Portal on the NERC website to provide one stop shopping for stakeholders seeking answers to questions.
- Identify potential future processes to obtain expedited interpretations
- Identify expedited processes for adjusting NERC glossary terms
- Identify refinements for credentialing standard drafting team members to ensure the correct subject matter experts are developing the standards at both the Regional level and the ERO level.
- Establish targets for NERC and NPCC standards procedure improvement and support initiation of implementation of the strategy
- Streamline and improve the Regional Standards program tools and IT based solutions
- Refine the records retention programs to ensure sufficient documentation exists for regulatory approvals
- Develop document management systems to allow the efficient and effective revisions of documents, control of authorship and security of documents
- Identify improvements in process for feedback loops to ensure that event analysis and investigation lessons learned and compliance issues involving violations are fed into the standards program area, as appropriate for review and potential consideration when revising standards
- Support the creation of an ERO standards database, available to industry and online, to identify and review issues related to all approved and developing standards
- Participate in the Functional Model Working Group activities to refine functions, tasks and responsibilities of applicable entities
- Solicit and provide outreach to FERC in the Regional Standards Development Processes

7) Communications

- Improve automated notifications process to assure awareness of dates and proceedings of all standard development activities
- Strengthen the relationship with the industry's technical committees to ensure adequate input to standards development, such as the North American Generator Forum.
- Participate in NPCC and NERC workshops as necessary, to promote awareness and educate the industry
- Develop and institute a consensus building and notification process(es) for engaging stakeholders and providing immediate notification for the need to review standards. Provide the associated coordination for this review utilizing subject matter experts, both internal and external to the Regional Entity staff
- Promote the reliability objectives of the NERC standards as appropriate to the NPCC members of the NERC Registered Ballot Body in order to achieve consensus and support of beneficial standards and to promote the "One-Enterprise" model.

Technically excellent, results based standards that enhance reliability and are developed in a timely and efficient fashion, require the full participation of the right industry experts from all Regional Entities when developing Reliability Standards. The NPCC RSC promotes the drafting team process and solicits drafting team members from appropriate NPCC technical bodies and others in the industry and adjoining Regional Entities. In addition the NPCC RSC works with the individual NERC standards developers to participate in Regional outreach and coordination of issues at each NPCC RSC meeting.

NPCC RSC will also assist in providing notifications and announcements to NPCC participants in the Northeastern North America NERC Registered Ballot Body of important applicable deadlines for ballot pool registration and for casting ballots thereby enhancing participation, promulgation of important information and increasing awareness. In the fourth quarter of 2014 NERC will "roll out" a new Standards Balloting System (SBS). This new system will require training and an implementation communication plan. NERC will develop the training and NPCC will assist in providing it throughout the Northeast. The SBS will require all users to reregister to cast ballots as well as submit comments. This support will enhance efficiency of the NERC procedure and help to ensure the necessary quorums are present at ballot and help to clean up the registered ballot body list. NPCC will also, when practical, promote important standards and the requirements of those standards through various communications.

NPCC will also participate in the development and revision of standards as directed by FERC, Canadian provincial and other regulatory and/or governmental authorities. FERC to date has identified numerous NERC Reliability Standards needing further work and has issued numerous Directives appearing in FERC Orders. In 2013 FERC also issued remanded interpretations and standards which require NERC to address commissions concerns as outlined in the associated Orders. These remands have created a need for NERC to review existing processes and determine approaches going forward. NPCC will support these efforts and will lead the review and potential revision of the NERC Interpretation process. These standards needing revision are delineated in the 2014 – 2016 NERC Reliability Standards Development Plan, and will be ready to be reviewed and revised throughout 2015.

NPCC will provide support and coordination of NERC standards development activities as outlined in the 2014-2016 Reliability Standards Development Plan and the Standards Committee and ERO strategic goals and initiatives.

Regional Standards Development

The NPCC currently has two FERC approved Regional standards, Disturbance Monitoring and Underfrequency Load Shedding. NPCC has undertaken the review of the Disturbance Monitoring standard for adequacy from the perspective of a "bright line" BES definition and currently developing PRC-002-2 Disturbance Monitoring continent wide standard. This review of the standard and proposed revision to the standard will be performed in the 2014-2015 timeframe. In addition there are two other Regional standards that NPCC may review to determine if they should move forward into active formal development. These Regional Standards will include, but not be restricted to the following:

- Special Protection Systems (SPS) scheduled to begin development in 2014
  Balancing Authority Controls (BA - Reserve Sharing)

Whether NPCC pursues these Regional standard will depend in large part to how comprehensive their associated continent-wide standards are. NPCC will review the continent wide standards as they are develop, participating in those activities and providing supporting subject matter expertise as it is available.

Based on the portion of professional/technical staff time and other resources devoted to Reliability Standards development, NPCC estimates that it will expend approximately 10 percent of its resources on this activity.

Funding Sources and Requirements — Explanation of Increase (Decrease)

Funding Sources (Other than ERO Assessments)

- U.S. Penalty Sanctions remitted from 7/1/13 through 6/30/14 reduce U.S. LSE designee assessments for 2015.

Personnel Expenses

- NPCC anticipates no need to hire additional personnel in this program area in 2015.
- Salaries expense reflects implementation of recommendations of NPCC's Management Development and Compensation Committee, which were based on an independent compensation study.
- Benefits expense decreased due to more staff opting out of company sponsored health insurance for superior coverage through prior employer or spouse.
- Retirement expense decreased due to transition of employees formerly accruing benefits under the defined benefit plan to receiving defined contribution benefits in 2015.

Meeting and Travel Expenses

- Meeting expenses will be minimized due to a continued effort to keep costs down by holding more meetings via WebEx and teleconferences, at the NPCC offices or member facilities when possible, as well as lower meeting space rental rates through negotiations. However, meeting volume is expected to increase in 2015. Travel expenses due to continued practice of advance bookings, adjustments to class of hotel used, increased meetings at NPCC's offices, and meetings conducted via teleconference will be held to a minimum. Conference calls and Internet meetings, which are budgeted as a part of G&A and then allocated to the direct programs through indirect expenses, will be conducted for business when practical.

Operating Expenses and Indirect Expenses

- 2015 Reliability Standards program funding is driven by the need for additional activities to support NERC standards activity to achieve a results based, adequate, set of steady state standards, FERC activity and increased number of rulings and directives are anticipated as a result of the NERC three year work plan. NPCC anticipates expanded activity and plans to prioritize the efforts of existing resources to meet this expanded workload to support reliability and the ERO Strategic Goals. In addition, as standards reviews increase in number, there may be a need to have contractors assist due to constrained resources of NPCC Staff and members.

- NPCC total overhead expenses, such as office rent and office costs will be charged to the Administrative Services Programs and then reallocated proportionately based on FTE to the programs through Indirect Expenses.

Other Non-Operating Expenses

- None

Fixed Asset Additions

- None

Reliability Standards Program

Funding sources and related expenses for the Reliability Standards section of the 2015 business plan are shown in the table below.

Statement of Activities and Capital Expenditures 2014 Budget & Projection, and 2015 Budget						
Reliability Standards						
		2014 Budget	2014 Projection	Variance 2014 Projection v 2014 Budget Over(Under)	2015 Budget	Variance 2015 Budget v 2014 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ 1,431,239	$ 1,431,239	$ -	$ 1,426,577	$ (4,663)
	Penalty Sanctions	16,091	16,091	-	29,552	13,462
Total ERO Funding		**$ 1,447,330**	**$ 1,447,330**	**$ -**	**$ 1,456,129**	**$ 8,799**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops	-	-	-	-	-
	Interest	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Funding (A)		**$ 1,447,330**	**$ 1,447,330**	**$ -**	**$ 1,456,129**	**$ 8,799**
Expenses						
Personnel Expenses						
	Salaries	$ 502,840	$ 502,840	$ -	$ 535,458	$ 32,618
	Payroll Taxes	31,305	31,305	-	31,420	115
	Benefits	131,342	131,342	-	93,684	(37,658)
	Retirement Costs	87,449	87,449	-	85,075	(2,374)
Total Personnel Expenses		**$ 752,936**	**$ 752,936**	**$ -**	**$ 745,638**	**$ (7,299)**
Meeting Expenses						
	Meetings	$ 25,000	$ 25,000	$ -	$ 20,000	$ (5,000)
	Travel	110,000	110,000	-	115,000	5,000
	Conference Calls	-	-	-	-	-
Total Meeting Expenses		**$ 135,000**	**$ 135,000**	**$ -**	**$ 135,000**	**$ -**
Operating Expenses						
	Consultants & Contracts	$ 30,000	$ 30,000	$ -	$ 25,000	$ (5,000)
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
	Depreciation	-	-	-	-	-
Total Operating Expenses		**$ 30,000**	**$ 30,000**	**$ -**	**$ 25,000**	**$ (5,000)**
	Total Direct Expenses	**$ 917,936**	**$ 917,936**	**$ -**	**$ 905,638**	**$ (12,299)**
Indirect Expenses		**$ 555,686**	**$ 555,686**	**$ -**	**$ 561,221**	**$ 5,535**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 1,473,622**	**$ 1,473,622**	**$ -**	**$ 1,466,858**	**$ (6,764)**
Change in Assets		**$ (26,292)**	**$ (26,292)**	**$ -**	**$ (10,729)**	**$ 15,563**
Fixed Assets						
	Depreciation	$ -	-	$ -	-	$ -
	Computer & Software CapEx	-	-	-	-	-
	Furniture & Fixtures CapEx	-	-	-	-	-
	Equipment CapEx	-	-	-	-	-
	Leasehold Improvements	-	-	-	-	-
	Allocation of Fixed Assets	(26,292)	(26,292)	-	(10,729)	15,563
Inc(Dec) in Fixed Assets (C)		**(26,292)**	**(26,292)**	**-**	**(10,729)**	**15,563**
TOTAL BUDGET (=B+C)		**$ 1,447,330**	**$ 1,447,330**	**$ -**	**$ 1,456,129**	**$ 8,799**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ -**	**$ -**	**$ -**	**$ 0**	**$ (0)**

Compliance Monitoring and Enforcement and Organization Registration and Certification Program

Compliance Monitoring and Enforcement and Organization Registration and Certification Program Resources (in whole dollars)	2014 Budget	2015 Budget	Increase (Decrease)
Total FTEs	16.00	16.00	0.00
Direct Expenses	$5,080,485	$5,440,048	$359,564
Indirect Expenses	$3,034,462	$3,064,686	$30,225
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	($35,575)	$63,410	$98,985
Total Funding Requirement	$8,079,371	$8,568,145	$488,774

Program Scope and Functional Description

The Compliance Monitoring and Enforcement and Organization Registration and Certification Program (CORC) Program scope covers: 1) the identification, registration and certification of those entities responsible for meeting the NERC Reliability Standards and any approved Regional Standards; 2) the implementation of the NERC Compliance Monitoring and Enforcement Program (CMEP) in the United States, including the compliance monitoring, assessment and enforcement of NERC Reliability Standards and Regional Reliability Standards. and 3) the implementation of compliance monitoring, assessment and enforcement recommendations in accordance with individual executed MOUs or Agreements in the Canadian Provinces of Ontario, Québec, New Brunswick and Nova Scotia.

The NPCC Compliance Committee (CC) is charged with providing objective stakeholder policy input to NPCC's implementation of the CMEP in the U.S. and compliance related activities under the above mentioned MOUs in the NPCC portion of Canada. With regard to NERC Reliability Standards and Regional Reliability Standards, the CC provides an oversight role of the independent NPCC compliance staff's implementation of the CMEP. In this oversight role the CC will review and endorse the processes used by the NPCC compliance staff in the conduct of the CMEP.

The NPCC compliance staff makes the initial and final determination of alleged violations and determines appropriate penalties and sanctions in accordance with the NERC *Sanction Guidelines*. To accomplish this objective, NPCC's compliance staff is further divided into four sub- program areas: Compliance Implementation and Registration; Compliance Audit Program; Compliance Enforcement; and Compliance Investigation:

Compliance Implementation and Registration

The Compliance Implementation and Registration sub-program is responsible for:

a) Identifying for registration, using a risk based registration model, all entities that are required to meet the NERC and Regional Reliability Standards. During the course of this activity, regular communication with registered entities is promoted through face-to face meetings, compliance workshops, teleconferences and email;
b) Development and maintenance of all CMEP Compliance Procedures, Compliance Instructions and all other CMEP related documentation;
c) Development and maintenance of Performance Metrics that are used to measure the quality and effectiveness of CMEP Implementation and its impact on the reliability of the Bulk Electric System;
d) Coordinating the implementation of NPCC Compliance Staff responsibilities as they pertain to the executed MOU with each of the Canadian Provinces in the NPCC Region.
e) Day-to-day implementation of the CMEP;
f) Development of annual CMEP Implementation Plan;
g) Monitoring and assessment of self-certification, self-report, exception reporting, periodic data and complaint submittals;
h) Development and maintenance of CMEP Data Administration Application (CDAA);
i) Development and maintenance of compliance website.
j) Support the anticipated expansion of the number of registered entities in NPCC due to the implementation of the FERC Order related to the definition of Bulk Electric System
k) Conduct Entity Impact Evaluations. Conduct certification(s) of newly identified Transmission Operators (TOPs), as needed.
l) Maintain database of BES assets subject to NERC and NPCC Reliability Standards
m) Participation on various NERC and NPCC working groups to remain apprised of changes to Compliance processes, and commonality of registration, monitoring, auditing, and enforcement approaches.

Compliance Audit Program

The Compliance Audit Program is charged with conducting both on-site and off-site compliance audits, and spot checks, of NERC Reliability Standards in accordance with the NERC Rules of Procedure and associated NPCC procedures developed under the NPCC Compliance Implementation Program. These audits are performed on the basis of risk to the BES. The yearly schedule is produced consistent with Risk Assessment of registered entities and the frequency of their last audit. The schedule is posted annually on NERC and NPCC public websites. Flexibility may be used in the predefined frequency based on the risk assessment and performance based assessment of each entity scheduled for an audit, and changes requiring certification. The audits are led by qualified senior NPCC Staff and the audit teams prepare public and non-public audit reports with their findings, including the identification of any possible violations. Contents and processing of the reports are in accordance with NERC directives for audit reporting. Specific lessons learned are factored into the audit program to promote continuous improvement and are presented at workshops in conjunction with the Compliance Implementation Program. The comprehensive spot-check program is established based on the NERC actively monitored list, NPCC's assessment of self-certifications, follow–ups on entities who have previously violated a Reliability Standard, follow-up on entities that have been involved in a significant system event, and other requirements which at the discretion

of NPCC could pose a higher risk to reliability if not followed properly. The schedule for Spot Checks is not public.

Resources from the Compliance Audit Program are also used to implement the Certification process for entities intending to register as new TOPs, BAs or RCs, as well as certification reviews of changes made by existing TOPs, BAs and RCs that meet the threshold requiring same. These actions are performed in support of the Compliance Registration Program which encompasses the Certification process. Resources for this activity, which is independent of the audit process, depend on the scope, function, and location of the entity being certified.

Compliance Investigation

A Compliance Investigation (CI) may be initiated at any time by NPCC in response to a system disturbance, complaint, or possible violation of a Reliability Standard identified by any other means. The CI process requires the establishment of an investigation team that coordinates with NERC and FERC as necessary; and also coordinates with the Situation Awareness Program Area.

Compliance Enforcement

In processing identified violations NPCC Compliance Enforcement will strive to promote both timeliness and transparency of compliance results, including those efforts associated with meeting the enforcement metrics described below. In addition NPCC will promote the use of self-identification of non-compliance and implementation of discretion, including increased utilization of streamlined tracks such as FFT and discretion as shown below.

Compliance Enforcement responsibilities:

a) Issuing all Notices as described in the CMEP including the Notice of Possible Violation (NOPV), Notice of Find, Fix and Track (FFT) Treatment; Notice of Alleged Violation (NOAV), and the Notice of Confirmed Violation (NOCV);
b) Conducting comprehensive enforcement investigations based on the facts and circumstances related to all possible violations of Reliability Standards, whether identified in an audit, a self-report, complaint, or other source, and determining whether further action is warranted;
c) Reviewing, approving, submitting to NERC and tracking the progress of all mitigation plans /mitigating activities associated with confirmed violations;
d) Coordinating settlement activities once they have been initiated and submitting settlement agreements to NERC for approval;
e) Identifying and processing candidates for the FFT Process;
f) Participating in the Hearing Process by representing NPCC before the Hearing Body. Compliance Hearings would be conducted at NPCC under the supervision of a qualified, independent hearing officer contracted by NPCC;
g) Issuing Remedial Action Directives when appropriate; and
h) Implementing of the Reliability Assurance Initiative (RAI), including :
    i. Notifying the registered entity, within 60 days on average, whether a non-compliance will proceed through enforcement, be treated as a compliance exception or additional information is needed (“Triage”);
    ii. Utilizing the Aggregation of Minimal Risk Process; and
    iii. Utilizing the Enforcement Discretion Process.

A set of enforcement metrics, that include those metrics included in the ERO Corporate Goals, are produced that cover the following:

a. Caseload Index and Violation Aging
b. Mitigation Aging
c. Percentage of self-identified violations
d. Percentage of minimal and moderate risk violations through FFT, SNOP or discretion

Each of these metrics will have target values defined that are consistent with those target values identified in the ERO Corporate Goals.

2015 Key Assumptions and Cost Impacts

2014	Projected 2015
3 Large On-Site Audits	4 Large On-Site Audits
0 Medium On-Site Audits	0 Medium On-Site Audits
3 Small On-Site Audits	3 Small On-Site Audits
12 On-Site CIP Audits	4 On-Site CIP Audits
20 Large Off-Site Audits	8 Large Off-Site Audits
7 Medium Off-Site Audits	21 Medium Off-Site Audits
7 Small Off-Site Audits	10 Small Off-Site Audits
22 Off-Site CIP Audits	24 Off-Site CIP Audits
300 Spot Checks	350 Spot Checks
8 On-site TFE Part B reviews	4 TFE Part B Reviews
200 Violations (Estimated)	200 Violations (Estimated)
Settlements Covering 100 Violations	Settlements Covering 100 Violations
2 Hearings (Unbudgeted)	2 Hearings (Unbudgeted)
1 CI (Estimated)	1 CI (Estimated)
0 Entity Certifications	2 Entity Certifications

- Regarding the Compliance Audit Program, Technical Feasibility Exception (TFE) reviews are conducted both on-site at the entity's facility and at the NPCC offices when possible. TFE's continue to be requested as entities replace and install new equipment/devices/components that meet the criteria set forth in Rules of Procedure Appendix 4D. Compliance estimates 4 on-site reviews will be performed in 2015.

- Increases in Audit costs reflect Risk Assessment activity that is the basis for audit scoping. The Risk Assessment includes an assessment of an entity's Internal Controls which will be used for future audits in the scoping and frequency of engagements.
- Potential increases due to the newly identified role related to implementing the QCMEP in Quebec and the continuing role of implementing the NB CMEP in New Brunswick.

- The 2015 Business Plan projects no increases in Enforcement Processing activities over the 2014 Budget.
- The 2015 Business Plan projects the need for 1 Compliance Investigation. These Compliance Investigations are manpower intensive for NPCC staff (requiring allocation of more resources and potentially higher than normal costs) since previous Compliance Investigations have also included entities outside of NPCC's footprint for which NPCC is the Compliance Enforcement Authority.

2015 Goals and Key Deliverables

- Conduct 2015 CMEP consistent with the Reliability Assurance Initiative, incorporating Risk Assessment; Internal Control assessment; Aggregation of Minimal Risk Violations; and Enforcement Discretion and all NERC Reliability Standards contained in the NERC actively-monitored list for 2015 and any approved and applicable Regional Reliability Standards
  - Process identified violations as effectively as possible, including the timely identification of a violation, timely issuance of violation notices including the NOPV; the Notice of Alleged Violation and the NOCV
  - Implement settlement process when applicable and send proper notifications to NERC and FERC
  - Conduct necessary Hearings related to resolution of outstanding disputes regarding violations and/or sanctions. Send results of hearings to NERC and FERC[17];
- Continue to enhance the settlement process by modifying existing practices and adopting new practices to reduce the duration of settlement negotiations without sacrificing the rigor and quality of the negotiated settlements. Develop and analyze appropriate performance metrics that track settlement process duration and utilize results of analysis to further enhance process.
- Implement compliance responsibilities identified in the approved Canadian MOUs[18];
- Annual report to NERC and Régie on NPCC implementation of QCMEP
- Annual report to NERC and New Brunswick Electric Utility Board (EUB) on NPCC implementation of NB CMEP.
- Review and revise NPCC Compliance Registry based on a risk-based approach[19] ;
- Evaluate CMEP and Canadian entity compliance program implementation with the objective of establishing a long-term strategy for compliance improvement, and initiate the implementation of the long term strategy[20];
- Provide NPCC Regional Entity input, through participation in appropriate NERC compliance committees, on policy and implementation issues related to compliance and enforcement including the development of compliance elements for all new or revised NERC Reliability Standards[21];

[17] In support of ERO Goal 2. Be a strong enforcement authority that is independent, without conflict of interest, objective and fair.
[18] In support of ERO Goal 3. Promote a culture of compliance that supports reliability excellence within industry.
[19] In support of ERO Goal 2. Be a strong enforcement authority that is independent, without conflict of interest, objective and fair.
[20] ERO Goal 2. Be a strong enforcement authority that is independent, without conflict of interest, objective and fair.
[21] ERO Goal 6. Promote a culture of reliability excellence.

- Provide required information to NERC on a timely basis including reporting of alleged violations and confirmed violations[22];
- Track the progress of, report status of, and approve mitigation plans[23];
- Conduct 2015 Compliance Audit Schedule based on risk to the BES and number of registered entities (Each audit covers a single registered entity that could be audited for multiple Functional Model types that they are registered for and is done in accordance with the 2015 Compliance Audit Program schedule)[24] ; and promote RAI initiatives by:
    - Utilizing the Audit Checklist and Auditor's Handbook for all on-site and off-site audits
    - Preparing a Risk Assessment and Internal Control Assessment for all on-site audits[25];
- In addition, 28 registered entities will be audited for the requirements of the version in place for CIP 002 to CIP 009. These will be separate audits. On-site CIP audits may be combined with the normally scheduled 2015 on-site audits[26];
- A spot check can be viewed as a limited unscheduled small off-site compliance audit that will be utilized to verify self-certification submittals that have been done earlier in the year or other requirements based on factors as described in the Compliance Audits section. In 2015 the number of spot checks to be done is estimated to be 350[27] ;
- Assure that NPCC Staff is trained to conduct Compliance Audits including CIP Compliance Audit training[28];
- Assure that NPCC Staff is trained to conduct Certification of entities intending to Register as BA, RC or TOP for the first time, or Certification Reviews of changes by existing BAs, RCs or TOPs that meet the criteria requiring a Certification Review[29];
- NPCC is working with the other Regions to access, train and perform certifications (and re-certification) in an effort to be consistent across the ERO[30] ;
- Continue to actively perform a risk profile of each entity prior to audit and upon completion of an audit, continue to identify risk and reliability gaps[31] ;

[22] ERO Goal 2. Be a strong enforcement authority that is independent, without conflict of interest, objective and fair.
[23] ERO Goal 2. Be a strong enforcement authority that is independent, without conflict of interest, objective and fair.; ERO Goal 5. Be accountable for mitigating reliability risks.
[24] In support of ERO Goal 3a. and 3b. Promote a culture of compliance that supports reliability excellence within industry.
[25] In support of ERO Goal 3. Promote a culture of compliance that supports reliability excellence within industry.
[26] In support of ERO Goal 3. Promote a culture of compliance that supports reliability excellence within industry.
[27] In support of ERO Goal 3. Promote a culture of compliance that supports reliability excellence within industry.
[28] In support of ERO Goal 3. Promote a culture of compliance that supports reliability excellence within industry.
[29] In support of Goal 2a. Be a strong enforcement authority that is independent, without conflict of interest, objective, and fair, and promote a culture of reliability excellence through risk-informed compliance monitoring and enforcement. a. The ERO registers and deregisters entities commensurate with risk to the BES and ensures all key reliability entities are certified to have essential capabilities.
[30] In support of Goal 2a. Be a strong enforcement authority that is independent, without conflict of interest, objective, and fair, and promote a culture of reliability excellence through risk-informed compliance monitoring and enforcement. a. The ERO registers and deregisters entities commensurate with risk to the BES and ensures all key reliability entities are certified to have essential capabilities.
[31] In support of Goal 4a. Identify the most significant risks to reliability, be accountable for mitigating reliability risks, and promote a culture of reliability excellence. a. Risks are identified and prioritized based on reliability impacts, cost and practicality of assessments, projected resources, and emerging issues.

- Develop and implement compliance reform via the Reliability Assurance Initiative (RAI) by being an integral participant in committees and workgroups involved in the RAI[32];
- Promote a culture of compliance that addresses reliability risks of NPCC registered entities by using reliability gap analysis. Assess and evaluate registered entity's Internal Controls as part of the audit and spot check process[33];
- Continue to expand the use of discretion through the utilization of compliance exception. [34] ;
- NPCC will collaborate with NERC to promote better coordination, planning, delivery and management of training efforts across the enterprise through a unified learning management system (LMS), without adversely impacting region-specific training requirements;
- Continue to implement physical security outreach and Cyber Security outreach by visiting four registered entity sites to perform an assessment of their physical security, evaluate their Cyber Security and supply recommendations for improvements[35];
- Enhance the CDAA to expand its capabilities from both the registered entity perspective and the NPCC Compliance Staff perspective[36];
- Conduct 2015 Compliance Workshops and interim information sessions for registered entities as necessary as a part of Training and Education program area[37].

Adopt and promote practices to enhance the benefits of the self-reporting of violations by both the Regional Entity and the registered entity. This would include improvement to the registered entity internal processes used for identifying and submitting self-reports (e.g. adoption of an aggregated approach for submittal of self-reports, etc.), improvement in the way Regional Entities process self-reports and the streamlining and standardizing of the amount and type of data needed to evaluate a self-report.

[32]In support of Goal 3a. Promote a culture of compliance that supports reliability excellence within industry. a. Industry has effective procedures and programs to monitor, detect, correct, report, and prevent compliance, reliability, and security issues.

[33]In support of Goal 3a and 4a Goal 3. Promote a culture of compliance that supports reliability excellence within industry. Industry has effective procedures and programs to monitor, detect, correct, report, and prevent compliance, reliability, and security issues. Goal 4. Identify the most significant risks to reliability, be accountable for mitigating reliability risks, and promote a culture of reliability excellence. a. Risks are identified and prioritized based on reliability impacts, cost and practicality of assessments, projected resources, and emerging issues.

[34]In support of Goal 2b. Goal 2. Be a strong enforcement authority that is independent, without conflict of interest, objective, and fair, and promote a culture of reliability excellence through risk-informed compliance monitoring and enforcement. 2.b. The ERO holds industry accountable for violations that create serious risk to the BES; resulting actions are timely and transparent to industry.

[35]In support of Goal 4c. Goal 4. Identify the most significant risks to reliability, be accountable for mitigating reliability risks, and promote a culture of reliability excellence. 4.c. ERO supports industry situational awareness and cybersecurity preparedness and provides independent reliability information to policy makers.

[36]In support of Goal 5c. Goal 5. Improve transparency, consistency, quality, and timeliness of results; operate as a collaborative enterprise; and improve efficiencies and cost-effectiveness. 5.c. The ERO internal risks are understood and managed; ERO processes are effective, efficient, and continuously improved.

[37]In support of Goal 5a. Goal 5. Improve transparency, consistency, quality, and timeliness of results; operate as a collaborative enterprise; and improve efficiencies and cost-effectiveness. 5.a. The ERO acts in a coordinated and collaborative manner with stakeholders.

Based on the portion of professional/technical staff time and other resources devoted to Compliance monitoring and enforcement and organizational registration and certification, NPCC estimates that it will expend 58 percent of its resources on this activity.

Funding Sources and Requirements — Explanation of Increase (Decrease)

Funding Sources (Other than ERO Assessments)

- U.S. Penalty Sanctions remitted from 7/1/13 through 6/30/14 reduce U.S. LSE designee assessments for 2015.

Personnel Expenses

- NPCC anticipates no need to hire additional personnel in this program area in 2015.
- Salaries expense reflects implementation of recommendations of NPCC's Management Development and Compensation Committee, which were based on an independent compensation study.
- Benefits expense decreased due to more staff opting out of company sponsored health insurance for superior coverage through prior employer or spouse.
- Retirement expense decreased due to transition of employees formerly accruing benefits under the defined benefit plan to receiving defined contribution benefits in 2015.

Meeting and Travel Expenses

- Meeting expenses will be minimized due to a continued effort to keep costs down by holding more meetings via teleconference, at the NPCC offices or member facilities, combining or appending meetings to other mandatory training/meetings, as well as lower meeting space rental rates through negotiations. Travel expenses due to continued practice of advance bookings, adjustments to class of hotel used, increased meetings at NPCC's offices, and meetings conducted via teleconference will be held to a minimum, however, the amount of activity is expected to increase in 2015. Conference calls and internet meetings, which are budgeted as a part of G&A and then allocated to the direct programs through indirect expenses, will be conducted for business when possible.

Operating Expenses and Indirect Expenses

- Consultant and contractor costs increased due to increased workload related to the initial implementation of RAI, incorporating Risk Assessment and Internal Control assessment. Without this one time ramp up in RAI endeavors for 2015, contractor costs would have remained relatively flat. These joint ERO Enterprise initiatives are intended to benefit the registered entities, Regional Entities and NERC. With a risk and performance based assessment of each registered entity, audits will transition to a periodicity more reflective of the risk profile of the entity such that some audits will be more in-depth while others may have a reduced scope which will require less independent contractor resources.

- NPCC total overhead expenses, such as office rent and office costs, will be charged to the Administrative Services Programs and then reallocated proportionately based on FTE to the programs through Indirect Expenses.

Other Non-Operating Expenses

- None

Fixed Asset Additions

- Software development costs related to CMEP Data Administration Application (CDAA) and Compliance Issues Tracking System (CITS) enhancements are projected to continue into 2015.

Compliance Monitoring and Enforcement and Organization Registration and Certification Program

Funding sources and related expenses for the compliance enforcement and organization registration and certification section of the 2015 business plan are shown in the table below.

Statement of Activities and Capital Expenditures
2014 Budget & Projection, and 2015 Budget
Compliance Monitoring and Enforcement and Organization Registration and Certification

	2014 Budget	2014 Projection	Variance 2014 Projection v 2014 Budget Over(Under)	2015 Budget	Variance 2015 Budget v 2014 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 7,991,503	$ 7,991,503	$ -	$ 8,406,767	$ 415,263
Penalty Sanctions	87,868	87,868	-	161,378	73,510
Total ERO Funding	**$ 8,079,371**	**$ 8,079,371**	**$ -**	**$ 8,568,145**	**$ 488,774**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	-	-	-	-	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 8,079,371**	**$ 8,079,371**	**$ -**	**$ 8,568,145**	**$ 488,774**
Expenses					
Personnel Expenses					
Salaries	$ 2,287,504	$ 2,287,504	$ -	$ 2,393,832	$ 106,328
Payroll Taxes	162,571	162,571	-	162,511	(59)
Benefits	537,087	537,087	-	479,499	(57,588)
Retirement Costs	298,890	298,890	-	284,206	(14,684)
Total Personnel Expenses	**$ 3,286,052**	**$ 3,286,052**	**$ -**	**$ 3,320,048**	**$ 33,997**
Meeting Expenses					
Meetings	$ 25,000	$ 25,000	$ -	$ 32,000	$ 7,000
Travel	375,000	375,000	-	360,000	(15,000)
Conference Calls	-	-	-	-	-
Total Meeting Expenses	**$ 400,000**	**$ 400,000**	**$ -**	**$ 392,000**	**$ (8,000)**
Operating Expenses					
Consultants & Contracts	$ 1,394,433	$ 1,394,433	$ -	$ 1,728,000	$ 333,567
Office Rent	-	-	-	-	-
Office Costs	-	-	-	-	-
Professional Services	-	-	-	-	-
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Depreciation	-	-	-	-	-
Total Operating Expenses	**$ 1,394,433**	**$ 1,394,433**	**$ -**	**$ 1,728,000**	**$ 333,567**
Total Direct Expenses	**$ 5,080,485**	**$ 5,080,485**	**$ -**	**$ 5,440,048**	**$ 359,564**
Indirect Expenses	**$ 3,034,462**	**$ 3,034,462**	**$ -**	**$ 3,064,686**	**$ 30,225**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 8,114,946**	**$ 8,114,946**	**$ -**	**$ 8,504,735**	**$ 389,788**
Change in Assets	**$ (35,575)**	**$ (35,575)**	**$ -**	**$ 63,410**	**$ 98,985**
Fixed Assets					
Depreciation	$ -	-	$ -	$ -	$ -
Computer & Software CapEx	108,000	108,000	-	122,000	14,000
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	(143,575)	(143,575)	-	(58,590)	84,985
Inc(Dec) in Fixed Assets (C)	**(35,575)**	**(35,575)**	**-**	**63,410**	**98,985**
TOTAL BUDGET (=B+C)	**$ 8,079,371**	**$ 8,079,371**	**$ -**	**$ 8,568,145**	**$ 488,774**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**$ (0)**	**$ (0)**	**$ -**	**$ (0)**	**$ 0**

Reliability Assessment and Performance Analysis Program

Reliability Assessment and Performance Analysis Program Resources (in whole dollars)	2014 Budget	2015 Budget	Increase (Decrease)
Total FTEs	5.83	5.83	0.00
Direct Expenses	$1,888,972	$1,958,577	$69,605
Indirect Expenses	$1,105,682	$1,116,695	$11,013
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	($52,315)	($21,349)	$30,967
Total Funding Requirement	$2,942,339	$3,053,923	$111,585

Program Scope and Functional Description

NPCC, through its top technical committee, the Reliability Coordinating Committee (RCC), integrates the deliverables of its Task Force's and Working Group's Reliability Assessment and Performance Analysis related activities. Consistent with the applicable NERC Reliability Standards, these efforts include:

- Reviewing the adequacy of the NPCC systems to supply load considering forecast demand, installed and planned supply and demand resources and required reserves in accordance with NPCC Reliability Directory No. 1 and other related reliability directories; and,
- Assessing the impact of planned transmission and resource additions or modifications on NPCC system reliability in accordance with NPCC Reliability Directory No. 1 and other related reliability directories.

Seasonal assessments of the overall NPCC resource adequacy assessments are performed and possible actions to mitigate any potential problems are identified. NPCC reviews operations and disturbances both internal and external to the Region in order to identify any lessons to be learned and recommends any necessary follow-up actions.

If appropriate, enhancements to Regional Standards or NPCC's more stringent, Regionally-specific reliability requirements are also recommended. NPCC promotes and conducts both inter-Area and inter-Regional studies to enhance reliability and operational effectiveness, and provides a forum for the discussion and coordination of operating issues within the NPCC Region and with other Regions.

2015 Key Assumptions

Support of identified key NERC Reliability Assessment and Performance Analysis (RAPA) projects; [38] NERC and Regional Entities will gather data or perform analysis in support of U.S. Federal and NERC initiatives, such as:

- Report Recommendation from the "*NERC Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances (GMD) on the Bulk Power System*", including:
  i. enhancing system models in support of the study of GMD impacts;
  ii. Enhancing GMD notification procedures; and,
  iii. Determining optimum locations for monitoring capability on transformers, based on studies and operational experience.
- Follow-up study from the recommendations of the "*2013 NERC Special Reliability Assessment: Increasing Dependence on Natural Gas for Electric Power – Phase II: A Vulnerability and Scenario Assessment for the North American Bulk Power System;*"
- System frequency response analysis; and,
- Assessing reliability issues resulting from compliance to final EPA environmental regulations, reliable integration of new technologies as renewable energy, smart grid, energy storage, and/or reliability assessment of increased penetration of electric vehicles.

In support of NERC's 2015 Business Plan and Budget Program Area Services and Activities, NPCC will continue to:

- Vet proposed and future metric development, collection, and analysis with industry stakeholders and identify and spotlight trends through assessments of the availability data systems and metrics (e.g., TADS, DADS, GADS, TADS, SED, etc.)
- Conduct post-seasonal assessments (Summer and Winter) and additional scenario and special reliability assessments as required. Specialized contractors may be used to complete detailed analysis to support scenario assessments. Special reliability assessments currently proposed may include: changes in resource mix due to environmental regulations, electric/gas system interdependency, delays in proposed transmission development in the reliable integration of renewable resources.

In addition, NPCC supports:

- Development of NERC's Reliability Assessment Data System (RADS), [39] for the reporting and validation of the NERC Reliability Assessment Subcommittee Seasonal and Long-Term Reliability Assessment data requirements.

[38] In support of ERO Goal 4.- Identify the most significant risks to reliability, be accountable for mitigating reliability risks, and promote a culture of reliability excellence

[39] In support of ERO Goal 5.c - The ERO internal risks are understood and managed; ERO processes are effective, efficient, and continuously improved.

- Evaluation of a common set of probabilistic reliability indices and probabilistic-based work products to supplement the NERC Long-Term Reliability Assessments;
- Coordination with event analysis, lesson learned [40] and model validation activities. [41] Specialized contractors may be used to complete detailed analysis to support model data collection and validation;
- Support of NERC PMO IT deployments; [42] and,
- Provide support and technical input for related BES risks identified by the NERC Reliability Issues Steering Committee (RISC). [43]

Definition of the Bulk Electric System (BES) Definition [44]

Implementation of the Bulk Electric System (BES) definition and Exception Process as of the July 1, 2014 BES Effective Date is not expected to significantly impact resources requirements in this program area for 2015. NPCC's 2014 survey of its registered entities did not indicate that an overwhelming number of NPCC BES Exception requests would be sought based on the filed BES Definition. Based on the Commission approved BES Definition [45] and the NPCC BES 2014 survey results, the 2015 RAPA personnel should be sufficient to process any NPCC BES Exception requests received in 2015.

NPCC will use the NERC PMO developed BESnet application and related BES reference and guidance documents to assist industry in the implementation of the BES definition approved by the Federal Energy Regulatory Commission. The BES reference and guidance documents, processes and tool are designed to provide industry with certainty and clarity about the implementation of the revised BES definition.

The procedure to request an exception from application of the BES definition is set forth in Appendix 5C to the NERC Rules of Procedure, effective July 1, 2014. The REMG formed the BES Exception Process Working Group (BEPWG) in 2012 – comprised of representations from the eight Regional Entities and NERC staff - to help create an efficient and effective Regional mechanism for processing Entity self-determined BES notifications and BES Exception requests. The activities of the BEPWG are expected to continue in 2015, in order to provide a Regional forum for consistent Regional BES Exception request review and 'lessons learned.'

[40] In support of ERO Goal 4.b - Events and system performance are consistently analyzed for sequence, cause, and remediation to identify reliability risks and trends and lessons learned.
[41] In support of ERO Goal 4.d - Reliability models and data accurately represent system behavior and are shared among stakeholders.
[42] In support of ERO Goal 5.c - The ERO internal risks are understood and managed; ERO processes are effective, efficient, and continuously improved.
[43] In support of ERO Goal 4.a - Risks are identified and prioritized based on reliability impacts, cost and practicality of assessments, projected resources, and emerging issues.
[44] In support of ERO Goal 2.a - The ERO registers and deregisters entities commensurate with risk to the BES and ensures all key reliability entities are certified to have essential capabilities.
[45] FERC Order Accepting the Revised [BES] Definition at: http://www.nerc.com/pa/RAPA/BES%20DL/2014-03-20%20BES%20-%20FERC%20Order%20Approving%20Revised%20Definition.pdf

Eastern Interconnection Reliability Assessment Group [46]

The primary function of the Eastern Interconnection Reliability Assessment Group (ERAG) is to augment reliability of the bulk-power system in the Eastern Interconnection through periodic reviews of generation and transmission expansion. These assessments are conducted by the ERAG Steering Committees. In addition, ERAG has the responsibility to develop the annual set of seasonal and future steady state and dynamic simulation base cases for use by the Regional Entities and other industry groups in the Eastern Interconnection. This is done through the ERAG Multi-Regional Modeling Working Group (MMWG). NPCC participates in the ERAG activities as one of the six Eastern Interconnection Regional Entities.

NPCC RAPA staff participates with the ERAG Management Committee and acts as the liaison between the ERAG MMWG and the NPCC SS-37 Working Group; activities include:

Management Committee Activities

- ✓ Oversee the steady state and dynamic simulation base case development;
- ✓ Make necessary changes to the modeling of governor-turbine control systems to achieve frequency response that more closely reflects actual response during system frequency deviation events. Oversee ERAG Multi-Regional Modeling Working Group (MMWG) changes to the dynamics base cases;
- ✓ Continue the review of the NERC governor survey information to assess how to revise the governor-turbine plant control models at most generators;
- ✓ Review the 2015 Summer and 2015-2016 Winter Assessments, including, the MRSS (MRO-RFC-SERC-SPP) and the R-N (RFC-NPCC) Assessments of anticipated inter-Regional, inter-Balancing Authority transfer limit conditions and sensitivities;
- ✓ Participate in discussions with NERC staff, North American Transmission Forum, NERC System Analysis and Modeling Subcommittee, FERC staff and possibly North American Generation Forum representatives regarding base case modeling improvements and future general industry modeling improvements;
- ✓ Develop ERAG Strategic Direction (i.e. anticipated new developments in MMWG process and system assessments); and,
- ✓ Confirm MMWG cases and assessments continue to have sufficient protections in place for use and transmittal of confidential data and information.

Multi-Regional Modeling Working Group Items

- ✓ Complete the steady state and dynamic simulation base cases for the 2015 series of cases;
- ✓ Complete necessary changes to the modeling of governor-turbine control systems to achieve frequency response that more closely reflects actual response during system frequency deviation events;
- ✓ Continue the review of the NERC governor survey information to assess how to revise the governor-turbine plant control models at most generators. Recommend the necessary changes in the models for specific generators;
- ✓ Incorporate dispatch information into the future and seasonal ERAG MMWG base cases so that the dispatches are more closely aligned with economic dispatch practices;

[46] In support of ERO Goal 4.d - Reliability models and data accurately represent system behavior and are shared among stakeholders.

- ✓ Determine how the Regional MMWG case development processes will change due to the use of the new web-based System Dynamics Data Base program;
- ✓ Verify procedures in the MMWG manual are followed;
- ✓ Check and confirm that the dynamic model data passes all applicable checks and acceptance criteria. Include 60 second steady state simulation of each case to detect numerical errors; and,
- ✓ Apply changes to the MMWG dynamics case so they are available for interconnection dynamics studies.

System Assessments Items

- ✓ Completion of 2015 Summer and 2015-2016 Winter Assessments, including, the MRSS and the R-N Assessments of anticipated inter-Regional, inter-Balancing Authority transfer limit conditions and sensitivities; and,
- ✓ Take additional steps to achieve consistency among the MRSS and the R-N study forums assessments and practices. Make additional recommendations to the ERAG Management Committee on how to complete this process.

NERC [47]

Through its Task Forces and Working Groups, NPCC will continue to provide the NPCC Regional perspective with active NPCC RAPA staff participation on the NERC Planning and Operating Committees and key related NERC Subcommittees, Task Forces and Working Groups:

- ✓ Reliability Assessment Data Working Group (RADWG);
- ✓ Protection System Mis-operations Task Force (PSMTF);
- ✓ Spare Equipment Database Task Force (SEDTF);
- ✓ Demand Response Availability Data System Working Group (DADSWG);
- ✓ Generating Availability Data System Working Group (GADSWG);
- ✓ Transmission Availability Data System Working Group (TADSWG);
- ✓ Model Validation Working Group (MVWG);
- ✓ Reliability Assessment Subcommittee (RAS) - Seasonal and Long-Term Reliability Assessments;
- ✓ System Analysis and Modeling Subcommittee (SAMS);
- ✓ Performance Analysis Subcommittee (PAS);
- ✓ Regional support and coordination of the NERC:
  - o Generator Availability Data System (GADS);
  - o Demand Availability Data System (DADS);
  - o Transmission Availability Data System (TADS);
  - o Spare Equipment Data Base System (SEDS);
- ✓ Incorporating any probabilistic reliability metrics required for the 2015 NERC Long-Term Reliability Assessment through the NPCC 2015 Long Range Adequacy Overview;
- ✓ Providing analytic support to ERO-RAPA group for the:
  - o Analysis of Relay and Special Protection System mis-operations;
  - o Regional coordination of data required for the calculation of metrics proposed by the NERC Reliability Metrics Working Group; and,
  - o Other activities as directed by the ERO-Executive Management Group.

[47] In support of ERO Goal 4 - Identify the most significant risks to reliability, be accountable for mitigating reliability risks, and promote a culture of reliability excellence.

As well as:

- ✓ Updating the NPCC Electric System Map; Producing the annual NPCC Load, Capacity, Energy, Fuels, and Transmission (LCEFT) Report
- ✓ Liaison with the New York Defensive Strategies Working Group in coordination and implementation of Synchro-Phasor measurement devices on the NPCC and neighboring systems and monitor related efforts of the NERC North American Synchro-Phasor Initiative;
- ✓ Processing BES Exception requests received through the BES Exception Process;
- ✓ Participating in on-going NERC analysis of the Eastern Interconnection Frequency Response;
- ✓ Developing NPCC guidelines for load modeling in system reliability studies;
- ✓ Conducting NPCC resource adequacy assessments addressing impacts of emerging reliability issues identified by NERC (e.g., environmental requirements, gas-electric system interdependency, distributed generation, delays in transmission plans, etc.);
- ✓ Coordinating any resulting NPCC inter-Area reliability analyses required to assess the proposed integration of related large-scale renewable resource proposals from Regional activities;
- ✓ Completing the 2015 NERC Seasonal (and post Seasonal) Reliability Assessments; and,
- ✓ Completing the 2015 NERC Long-Term Reliability Assessment.

2015 Goals and Key Deliverables

Task Force on Coordination of Planning

The primary mission of the NPCC Task Force on Coordination of Planning (TFCP) is to promote reliability through the coordination of NPCC Area and NERC planning processes and activities. In addition, the TFCP provides technical support regarding operating expertise to the NPCC Regional Standards Committee and the NPCC Compliance Committee as requested.

TFCP activities include, but are not limited to:

- Leading the NPCC Task Force review of the revision of NPCC criteria, guidelines, and procedures related to planning, and of those documents which provide for the uniform implementation, interpretation and monitoring of compliance with criteria, guidelines and procedures related to planning.
- Supporting the NPCC Directory Project by either drafting, reviewing or approving directories.
- Coordinating, monitoring, reviewing, and making recommendations on proposed or modified Special Protection Systems.
- Facilitating Wide-Area Planning by supporting the Joint ISO/RTO Planning Committee Activities, implementation of the Northeast Planning Protocol, and performing any NPCC interconnection reliability analyses, as required.
- Reviewing the overall reliability of the NPCC Areas and performing multi-Area probabilistic reliability assessments.
- Identifying and assisting in the development of new Regional Reliability Standards.
- Assisting the NPCC Compliance Subcommittee, to monitor and coordinate the compliance efforts of the Areas with NPCC planning documents and registered entities with NERC Reliability Standards.

- Reviewing the Standards Authorization Requests and NERC Reliability Standards as well as participating in the NERC process. Educating and informing NPCC membership and registered entities of developments.
- Ensuring coordination of data and assumptions for conducting NPCC planning studies (i.e. load forecasts, reserve requirements, DOE EIA 411 data, and new facilities)
- Monitoring the activities of other NPCC Task Forces to ensure coordination with planning activities.
- Reviewing the adequacy of the NPCC systems to supply load considering forecast demand, installed and planned supply and demand resources and required reserve margins in accordance with NPCC Directory No. 1 based on a schedule set forth in the Reliability Assessment Program.
- Coordinating the review of the compliance of future Area plans with the Basic Criteria, including an analysis of resource and transmission system additions, and the potential inter-Area effects of special protection systems, in accordance with NPCC Reliability Directory No.1 based on a schedule set forth in the Reliability Assessment Program. (Specific projects, which in the opinion of the Task Force could have an impact on the reliability of the NPCC Bulk Power System, may be reviewed outside of the set schedule).

Key TFCP Reliability Assessment and Performance Analysis Deliverables

- ✓ Coordinating activities related to reactive power and voltage control practices, which includes Under Voltage Load Shedding (UVLS) with the Task Force on Coordination of Operation and the Task Force on System Studies to ensure that developments in the NERC Planning Committee and its Subcommittees are addressed.
- ✓ Monitoring the actions of the NERC Performance Analysis Subcommittee (PAS).
- ✓ Monitoring the actions of the NERC System Analysis and Modeling Subcommittee (SAMS).
- ✓ Overseeing the A-10 BPS Implementation Plan.
- ✓ Overseeing the summer 2015 and winter 2015-2016 NPCC multi-area probabilistic reliability evaluations.
- ✓ Overseeing the 2015 NPCC Long-Range Adequacy Overview.
- ✓ Evaluating and approving Balancing Authority Area Transmission Reviews.
- ✓ Coordinating, monitoring, reviewing, and making recommendations on the retirement of existing in-service Special Protection Systems (SPS); and the implementation of proposed new or modified Special Protection Systems.
- ✓ Review the NPCC SPS criteria with respect to proposed NERC SPS Standards.
- ✓ Monitoring industry practices and making recommendations to NPCC on transmission adequacy standards related to intermittent generation such as wind or solar-voltaic.
- ✓ Reviewing and giving direction to other task forces on changes required to the Underfrequency Load Shedding (UFLS) program required to take into account increasing amounts of distribution connected generation and/or intermittent generation.
- ✓ Evaluating and recommending approval of NPCC Balancing Authority Area Resource Adequacy Assessments.
- ✓ Monitoring the developments in demand resources, energy efficiency, distributed generation and conservation methods including all intermittent renewable resources.
- ✓ Conducting resource adequacy assessment studies addressing emerging reliability issues as identified by the NERC Planning Committee (e.g., environmental requirements, etc.)
- ✓ Supporting Joint ISO/RTO Planning Committee activities.

- ✓ Facilitating Wide-Area Planning through participation in Regional and coordinating any resulting required inter-Area Reliability Assessment of the proposed integration related large-scale renewable resource proposals.
- ✓ Completion of the NERC 2015 Long-Term Reliability Assessment.
- ✓ Completion of the 2015 Review of NPCC Interconnection Assistance Reliability Benefits Study.
- ✓ Review NERC Events Analysis Lessons Learned for consideration in TFCP activities and processes.

Task Force on System Studies

The primary mission of the NPCC Task Force on System Studies (TFSS) is to provide active overall coordination of system studies of the reliability of the interconnected bulk power systems and for the review of certain NPCC documents. In addition, the TFSS provides technical support regarding operating expertise to the NPCC Regional Standards Committee and the NPCC Compliance Committee as requested.

The activities of the TFSS include, but are not limited to:

- Participating with the Task Force on Coordination of Planning, the Task Force on Coordination of Operation, and the Task Force on System Protection in reviews of the NPCC Reliability Directory No.1 and other NERC Reliability Standards and NPCC criteria, guidelines, procedures and documents which provide for the uniform implementation, interpretation and monitoring of conformance to criteria, guidelines and procedures related to system studies.
- Conducting NPCC Balancing Authority Area Reviews, in accordance with NPCC Reliability Directory No. 1, based on material presented by the Balancing Authority Areas. These reviews will assess the impact of planned transmission and resource additions or modifications on system reliability, and determine the Balancing Authority Area's conformance with the NPCC Basic Criteria.
- Reviewing and approving changes to Balancing Authority Areas' lists of bulk power system elements, in accordance with the *Classification of Bulk Power System Elements* (Document A-10). Annually review and update the NPCC BPS List.
- Reviewing and classifying new and modified Special Protection Systems, in accordance with NPCC Reliability Directory No. 7. Annually reviewing and updating the NPCC Special Protection System List.
- Conducting such load flow, transient stability, and other studies as required analyzing the overall reliability of the planned bulk power transmission systems of NPCC and the interconnections between NPCC and other Regional reliability organizations. As a part of this effort, analyze potential inter-Area effects of Special Protection Systems.
- Conducting analytical studies as appropriate to support the coordination of system planning, system operation and system protection in NPCC.
- Maintaining, through the SS-37 Working Group, a library of load flow base cases and associated dynamics data, for use in and support of Balancing Authority Area Reviews, overall transmission assessments, operational studies, inter-Regional studies, etc. Coordinate this effort with the NERC inter-Regional base case development process.
- In conjunction with other Task Forces, reviewing major system disturbances to ascertain the adequacy of the interconnected systems. Also, reviewing any associated recommendations for system modifications and considering the need for criteria changes.

- Identifying and recommending improved system study techniques. This includes, but is not limited to, the following:
  - improved techniques and models for power system simulation;
  - improved techniques for power system Reliability Assessment;
- Conducting a periodic review of the adequacy of the NPCC underfrequency load shedding program. Annually reviewing and updating the NPCC underfrequency load shedding database.
- Maintaining a listing and monitoring the status of major transmission and generation projects within NPCC.
- Maintaining liaison with other NPCC Task Forces and report to the Reliability Coordinating Committee as required.
- Monitoring the work of industry research and development organizations such as the IEEE, Canadian Electricity Association, Electric Power Research Institute, CIGRE and other technical organizations.
- Annually developing updates to the NPCC Electric System Map

Key TFSS Reliability Assessment and Performance Analysis Deliverables:

- ✓ Conducting Balancing Authority Area reviews, in accordance with the *Guidelines for NPCC Area Transmission Reviews* (Appendix B of NPCC Reliability Directory No. 1), based on material presented by the Balancing Authority Areas. These reviews assess the impact of planned transmission and resource additions or modifications on system reliability, and determine the Area's conformance with the NPCC Basic Criteria. Through the Area Transmission Reviews, re-evaluate the performance and classification of existing SPSs and Dynamic Control Systems as appropriate.
- ✓ Reviewing and classifying new and modified Special Protection Systems, in accordance with NPCC Reliability Directory No. 7 *Procedure for NPCC Review of New or Modified Bulk Power System Special Protection Systems* as required.
- ✓ Reviewing and approving changes to the Balancing Authority Areas' lists of bulk power system elements, in accordance with the *Classification of Bulk Power System Elements* (Document A-10), as required.
- ✓ Updating the NPCC Bulk Power System List.
- ✓ Through the ad hoc Load Modeling Task Force, address the recommendations from the SS-38 Load Modeling White Paper regarding the use of dynamic load models for transient stability analysis.
- ✓ Perform the Overall NPCC Transmission Assessment.
- ✓ Reviewing and updating NPCC Undervoltage Load Shedding Database.
- ✓ Participation in on-going NERC analysis of the Eastern Interconnection Frequency Response.
- ✓ Through the SS-37 Working Group, develop the annual library of power flow base cases and associated dynamic models for use by NPCC members and input into the development of the MMWG library of power flow and dynamic cases and databases for the Eastern Interconnection
  - i. Final development of NPCC power flow models for 2015
  - ii. Final development of NPCC dynamic models for 2015
  - iii. Address wind modeling issues including maintaining a database of NPCC wind models for use in the MMWG library of power flow and dynamic cases and databases for the Eastern Interconnection.
- ✓ Annually performing event replication and exercise the procedure. Reviewing existing Regional criteria and procedures for validation of data used in power flow and dynamic

simulations by benchmarking against actual system performance. If the existing criteria or procedures are found to be deficient, propose changes to provide for adequate data validation

- ✓ Updating the NPCC SS-37 Working Group Procedure Manual and other related documents including the Master Tie line Data, and Interchange Schedule, as required.
- ✓ Providing mid-term updates to the Library of NPCC/MMWG cases
- ✓ Enhancing the governor modeling on a unit by unit basis suitable for use in the system simulation.
- ✓ Annually reviewing and updating a list of NPCC underfrequency load shedding.
- ✓ Coordinate activities with those of the New York State Defensive Strategies Working Group, regarding the coordination and implementation of Synro-Phasor measurement devices.
- ✓ Incorporate NPCC guidelines for load and power system modeling approved by the RCC
- ✓ Classification of Bulk Power System Elements.
- ✓ Participate at Siemens PTI User Group meetings to provide PSSE program enhancements
- ✓ Supporting Regional system studies to integrate large-scale renewable resources.
- ✓ Provide support to NERC Event Analysis process, as needed.
- ✓ Develop updates to the NPCC Electric System Map.
- ✓ Provide support to the NERC Model Validation Working Group (MVWG) as needed.
- ✓ Review NERC Events Analysis Lessons Learned for consideration in TFSS activities and processes.

Task Force on System Protection (TFSP)

The purpose of the NPCC Task Force on System Protection (TFSP) is to promote the reliable and efficient operation of the interconnected bulk power systems in Northeastern North America through the establishment of directories, criteria, guidelines, and procedures and coordination of design, relative to the protection associated with the bulk power systems. In addition, the TFSP provides technical support regarding operating expertise to the NPCC Regional Standards Committee and the NPCC Compliance Committee as requested.

The Reliability Assessment and Performance Analysis activities of the TFSP include, but are not limited to:

- Assessing proposed protection systems and special protection systems in accordance with NPCC Reliability Directory No. 4 and No. 7.
- Reviewing and analyzing the performance of protection systems following selected major power system disturbances and events, inside as well as outside NPCC in accordance with NPCC Reliability Directory No. 4. Issue recommendations for changes to NPCC Documents, as appropriate.
- Providing technical advice on protection issues to NPCC and coordinate with other Task Forces on the application of Intelligent Electronic Devices (IEDs) that include functions related to energy management systems in addition to their protective functions, in order to safeguard the integrity of the protective functions.
- Through the SP-7 Working Group, review, on a quarterly basis all protection system (including special protection system) misoperations reported to NPCC.
- Reviewing and assessing significant protection issues of common interest or informational value.
- Reviewing and assessing regulatory and industry based documents as they relate to system protection.

- Maintaining an effective liaison with North America groups working in the protection areas (for example: NERC System Protection & Control Subcommittee.)
- Exchanging information with other power pools, Regional Reliability Councils, Regional Transmission Organizations and other industry groups on matters concerned with system protection.
- Identifying the need for special studies and new documents, recommend action to the Reliability Coordinating Committee.

Key TFSP Reliability Assessment and Performance Analysis Deliverables:

- ✓ Assessing proposed protection systems and special protection systems for compliance with NPCC Directory No. 4 and No. 7 criteria.
- ✓ Reviewing and analyzing the performance of protection systems in power system disturbances and events, brought to the attention of the Task Force, inside as well as outside NPCC in accordance with *Procedures for Task Force on System Protection Review of Disturbances* (Document C-30). Issuing recommendations for changes to NPCC Documents, as appropriate.
- ✓ Develop a new NPCC Directory for Disturbance Monitoring Equipment for related criteria, guides and procedures.
- ✓ Participate or serve as lead Task Force in the development and/or implementation of Regional Reliability Standards.
- ✓ Providing support to the NERC Event Analysis process as required.
- ✓ Participate in the ongoing development and submission of NPCC input into the development of related NERC Reliability Standards.
- ✓ Conducting any follow-up to the bulk power system protection risk assessment as directed by the Reliability Coordinating Committee.
- ✓ Through the SP-7 Working Group, monitor the review of protection system (including special protection system) mis-operations as they occurred in the NPCC Region and participation in providing the NPCC input for NERC Metric ALR4-1 on Protection Mis-operations.
- ✓ Monitor and review industry activities on the mitigation of the effects of SMD on protection systems. Report to RCC on any significant findings.
- ✓ Review mitigations and/or progress reports for BPS Risk Reduction Implementation at each meeting and annually report to the RCC on the status of this implementation.
- ✓ Participate in the development and submission of NPCC inputs/comments into the development of protection related NERC technical documents.
- ✓ Review best practices from its members and industry to pull together design considerations for the new IEC 61850 protection implementation with the output being possible additions to NPCC Directory No. 4 and Directory No. 7.
- ✓ Review NERC Events Analysis Lessons Learned for consideration in TFSP activities and processes.

Task Force on Coordination of Operation

The NPCC Task Force on Coordination of Operation (TFCO) facilitates the coordination of operations among the NPCC Reliability Coordinator areas and adjacent NERC Regions to enhance the reliability of the bulk power system. In addition, the TFCO provides technical support regarding operating expertise to the NPCC Regional Standards Committee and the NPCC Compliance Committee as requested.

The activities of the NPCC TFCO include, but are not limited to:

- Conducting seasonal reviews of the overall reliability of the generation and transmission systems in NPCC, and coordinating these efforts with parallel assessments conducted by the NPCC Task Force on Coordination of Planning and by NERC. Reviewing the operational preparedness of NPCC and recommending possible actions to mitigate any potential problems identified for each operating period.
- Reviewing operations and system disturbances and providing any necessary follow-up, including the recommendation of remedial or mitigating actions.
- Facilitating the reliable operational integration of new bulk power system facilities.
- Coordinating the development of operating NPCC requirements and procedures affecting the reliability and operability of the bulk power system in coordination with, and as directed by, NERC and NPCC.
- Promoting and sponsoring inter-Balancing Authority Area and inter-Regional studies to enhance reliability and operational effectiveness of the bulk power system.
- Providing coordination of operating issues with other NPCC Task Forces and other Regions.
- Reviewing, and acting upon, NERC actions, motions and recommendations in relation to the operation of the power system.
- Formulating the position of the TFCO on NERC Standards, and providing this position to the NPCC Regional Standards Committee as appropriate.
- Providing assistance as requested by the NPCC Regional Standards Committee in the development of Regional Standards and Directories.
- Providing assistance as requested by the NPCC Compliance Committee in monitoring and coordinating the compliance efforts of the registered entities of NPCC.

Key TFCO Reliability Assessment and Performance Analysis Deliverables:

- ✓ Review and analyze the performance of Simultaneous Activation of Reserve implementation following an event to enhance the process. Manage the implementation of action items emanating from the NERC report, "High-Impact, Low-Frequency Event Risk to the North American Bulk Power System-June 2010," and its subsequent reports:
  - ➢ Severe Impact Resilience Severe Impact Resilience Task Force
  - ➢ Geomagnetic Disturbance Task Force
  - ➢ Cyber Attack Task Force
  - ➢ Spare Equipment Database Task Force
  - ➢ Smart Grid Task Force
- ✓ Monitor the development of the NERC North American Synchro-Phasor Initiative in its effort to establish an effective control monitoring tool.
- ✓ Provide assistance to the NPCC Regional Standards Committee in the second phase of the NPCC directories process.
- ✓ Review NPCC Reliability Coordinator Area Restoration Plans.
- ✓ Complete the NPCC 2015 summer and winter Operational Reliability Assessments.
- ✓ Completion of the NERC 2015 Seasonal Reliability Assessments.
- ✓ Review NERC Events Analysis Lessons Learned for consideration in TFCO activities and processes.
- ✓ Support the implementation of the NERC Cyber Standards, as required.

NPCC Regulatory/Governmental Affairs Advisory Group

The purpose of the NPCC Regulatory/Governmental Affairs Advisory Group is to promote NPCC interaction and coordination with Federal/State/Provincial governmental and/or regulatory agencies on a coordinated Regional basis, and identify and develop policy input for NPCC and Northeast Regional governmental and/or regulatory bodies.

The NPCC Governmental/Regulatory Affairs Advisory Group provides a forum where industry and governmental and/or regulatory representatives can exchange views and strive to develop consensus policy recommendations on reliability issues specific to the NPCC Region (Northeastern United States and Eastern Canada) and share actionable information among NPCC, NERC and other related governmental and/or regulatory agencies related to Regional energy and reliability matters.

Based on the portion of professional/technical staff time and other resources devoted to Reliability Assessment and Performance Analysis, NPCC estimates that it will expend 21 percent of its resources on these activities.

Funding Sources and Requirements — Explanation of Increase (Decrease)

Funding Sources (Other than ERO Assessments)

- U.S. Penalty Sanctions remitted from 7/1/13 through 6/30/14 reduce U.S. LSE designee assessments for 2015.

Personnel Expenses

- NPCC anticipates no need to hire additional personnel in this program area in 2015.
- Salaries expense reflects implementation of recommendations of NPCC's Management Development and Compensation Committee, which were based on an independent compensation study.
- Benefits expense decreased due to more staff opting out of company sponsored health insurance for superior coverage through prior employer or spouse.
- Retirement expense decreased due to transition of employees formerly accruing benefits under the defined benefit plan to receiving defined contribution benefits in 2015.

Meeting and Travel Expenses

- While the amount of activity continues to increase in 2015, due to the volume of work described above, meeting expenses will be minimized to the extent possible due to continued efforts to keep costs down by holding meetings via conference calls and internet meetings, which are budgeted as a part of G&A and then allocated to the direct programs through indirect expenses, conducting meetings at the NPCC offices or member facilities, as well as negotiating lower meeting space rental rates.

Operating Expenses and Indirect Expenses

- NPCC total overhead expenses, such as office rent and office costs will be charged to the Administrative Services Programs and then reallocated proportionately based on FTE to the programs through Indirect Expenses.

Other Non-Operating Expenses

- None

Fixed Asset Additions

- None

Reliability Assessment and Performance Analysis Program

Funding sources and related expenses for the Reliability Assessment and Performance Analysis section of the 2015 business plan are shown in the table below.

Statement of Activities and Capital Expenditures
2014 Budget & Projection, and 2015 Budget
Reliability Assessment and Performance Analysis

	2014 Budget	2014 Projection	Variance 2014 Projection v 2014 Budget Over(Under)	2015 Budget	Variance 2015 Budget v 2014 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 2,910,322	$ 2,910,322	$ -	$ 2,995,121	$ 84,799
Penalty Sanctions	32,017	32,017	-	58,802	26,785
Total ERO Funding	**$ 2,942,339**	**$ 2,942,339**	**$ -**	**$ 3,053,923**	**$ 111,585**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	-	-	-	-	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 2,942,339**	**$ 2,942,339**	**$ -**	**$ 3,053,923**	**$ 111,585**
Expenses					
Personnel Expenses					
Salaries	$ 904,028	$ 904,028	$ -	$ 937,098	$ 33,070
Payroll Taxes	60,329	60,329	-	61,387	1,058
Benefits	226,225	226,225	-	196,252	(29,973)
Retirement Costs	190,390	190,390	-	172,840	(17,550)
Total Personnel Expenses	**$ 1,380,972**	**$ 1,380,972**	**$ -**	**$ 1,367,577**	**$ (13,395)**
Meeting Expenses					
Meetings	$ 45,000	$ 45,000	$ -	$ 41,000	$ (4,000)
Travel	175,000	175,000	-	185,000	10,000
Conference Calls	-	-	-	-	-
Total Meeting Expenses	**$ 220,000**	**$ 220,000**	**$ -**	**$ 226,000**	**$ 6,000**
Operating Expenses					
Consultants & Contracts	$ 275,000	$ 275,000	$ -	$ 365,000	$ 90,000
Office Rent	-	-	-	-	-
Office Costs	13,000	13,000	-	-	(13,000)
Professional Services	-	-	-	-	-
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Depreciation	-	-	-	-	-
Total Operating Expenses	**$ 288,000**	**$ 288,000**	**$ -**	**$ 365,000**	**$ 77,000**
Total Direct Expenses	**$ 1,888,972**	**$ 1,888,972**	**$ -**	**$ 1,958,577**	**$ 69,605**
Indirect Expenses	**$ 1,105,682**	**$ 1,105,682**	**$ -**	**$ 1,116,695**	**$ 11,013**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 2,994,654**	**$ 2,994,654**	**$ -**	**$ 3,075,272**	**$ 80,618**
Change in Assets	**$ (52,315)**	**$ (52,315)**	**$ -**	**$ (21,349)**	**$ 30,967**
Fixed Assets					
Depreciation	$ -	-	$ -	$ -	$ -
Computer & Software CapEx	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	(52,315)	(52,315)	-	(21,349)	30,967
Inc(Dec) in Fixed Assets (C)	**(52,315)**	**(52,315)**	**-**	**(21,349)**	**30,967**
TOTAL BUDGET (=B+C)	2,942,339	2,942,339	-	3,053,923	111,585
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**$ 0**	**$ 0**	**$ -**	**$ 0**	**$ 0**

Training, Education, and Operator Certification Program

Training, Education, and Operator Certification Program Resources (in whole dollars)	2014 Budget	2015 Budget	Increase (Decrease)
Total FTEs	0.10	0.10	0.00
Direct Expenses	$177,787	$180,222	$2,434
Indirect Expenses	$18,965	$19,154	$189
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	($897)	($366)	$531
Total Funding Requirement	$195,855	$199,010	$3,154

Program Scope and Functional Description

The NPCC Training, Education, and Operator Certification program supports NERC Rules of Procedure Section 900. The program provides education and training necessary to understand and operate the bulk electric system. The target audience of the program is bulk power system operating personnel - including system operations personnel, operations support personnel (engineering and information technology), supervisors and managers, and training personnel. This program also supports the administration of records necessary to maintain status as a NERC Continuing Education provider. NPCC staff training and development is incorporated within each respective program area.

Training Program Background and Description

NPCC establishes and coordinates programs for system operator training relating to inter-Reliability Coordinator area matters, criteria, terminology, standards and operating procedures and instructions. It develops and conducts training seminars, held twice yearly, at which potential operational problems for the coming season are discussed, the implementation of NPCC standards and procedures are discussed, significant disturbances are reviewed for lessons to be learned and table-top drills and communication and coordination exercises are conducted. The seminars promote camaraderie and better communication among system operators from the NPCC Reliability Coordinator Areas.

NPCC shares, evaluates and proposes new techniques and training aids as they become available; reviews opportunities to consolidate training among the NPCC Reliability Coordinators, which includes opportunities to share training material and training sessions and exchanges information on internal methods of system operator selection and training.

In addition, NPCC participates in the activities of the NERC Staff Training Group (STG). The main objective of the NERC STG is to coordinate the development of Regional Entity and NERC staff training and registered entity education materials to support and continually enhance reliability across North America for the benefit of all bulk electric system users, owners, and operators. The main focus of this group has been on NERC compliance auditor training.

Funding Drivers and Reliability Benefits

- Provide two high-quality continuing education seminars for system operators
    - System operators participating in the Seminars get exposure to NPCC issues and current industry operations topics, review recent NPCC or major external disturbances, discuss projected conditions for the coming summer or winter peak season and participate in hands on "table top exercises" pertaining to system operation practices. PJM operators also attend and participate in these seminars.
    - Seminar attendees also receive Continuing Education Hours (CEHs) and each Balancing Authority Area utilizes the seminar content by including it in their internal training programs to provide CEHs to all system operators
    - The seminars help to improve system operation coordination through better camaraderie among operators
- Review and revise the curriculum of the training seminars to better emphasize NERC standards, Regional Standards and business practices, NPCC wide-area operations and Regionally-specific criteria and procedures.[48]
- Enhance the system operator's awareness and knowledge of the standards, criteria and procedures they apply in real time operation.[49]
- Provide more sharing of new training approaches, exchange of information on internal methods of system operator selection, training material and training sessions.
    - Enhance efficiency and cost savings in the training programs in the NPCC Balancing Authority Areas
- Provide a forum among NPCC Reliability Coordinator / Balancing Authority (RC / BA) Areas for sharing of approaches to meet the requirements of the NERC PER standards. The sharing of approaches used by some NPCC Areas to address the PER-005-1, Requirement 3.1 on Training using simulator technology has been especially valuable to CO-2 Working Group members.
- Determine what changes would be needed for the NPCC Reliability Coordinator / Balancing Authority Areas to meet proposed expanded Systematic Approach to Training (SAT) requirement for operations support staff in PER-005-2.

2015 Key Assumptions

NPCC will conduct two workshops in 2015, for NPCC Stakeholders, for the express purpose of providing the most current and applicable information related to the development of NERC and Regional Reliability Standards and the implementation of the Compliance Monitoring and Enforcement Program (CMEP). These workshops are specifically designed, primarily through the conduct of targeted breakout class room sessions and presentations on current industry related activities, to provide for the most efficient exchange of information between the NPCC Compliance and Standards Staff and the NPCC Stakeholders. Presentations in the past have been conducted by FERC, NERC and Stakeholder representatives in addition to NPCC Staff members. To supplement these workshops, NPCC is also considering expanding the use of on-

[48] In support of ERO goal 4.b. Provide lessons learned and recommendations from events and identified risks.
[49] In support of ERO goal 4.b. Analyze significant events to identify gaps in standards, compliance effectiveness, registration, and risk controls effectiveness.

line webinars. These webinars will focus on a specific topic pertinent to developments related to compliance program implementation, standards development or technical topics.

NPCC also regularly conducts spring and fall System Operator Seminars. These seminars involve system operators from the NPCC Reliability Coordinator / Balancing Authority Areas and PJM. These will be held in early May and early November.

With the exception of meeting expenses, it is proposed that the NPCC resources to support Training and Education will remain virtually unchanged for the calendar year. In 2015, to be consistent with NERC and other Regional Entities, NPCC will charge for participation in NPCC workshops in an effort to defray some of the costs.

2015 Goals and Key Deliverables

- Prepare and conduct the spring and autumn NPCC System Operator Seminars
- Review approaches to reliability related-task definition, task instruction, and instruction tracking on an individual basis. Coordinate the effects of the PER-005-2 expanded SAT training requirements within the NPCC RC / BA Area programs.
- Expand the content of the Reliability Coordinator training programs, based on the new requirements generated by PER-005-2.
- Continue collaboration and sharing of the intended RC / BA approaches, experiences and materials to task identification and training development associated with NERC Standard PER-005-2.
- Create and expand the restricted-access NPCC repository of training resources and learning verification activities addressing fundamental power system topics, training methods and operation procedure training exercises, which may be shared as elements of operator training in compliance with NERC Standard PER-005, “System Personnel Training”.
- Participate in NERC Staff Training Group activities and provide NPCC input to the development of training policies by this group.

Based on the portion of professional/technical staff time and other resources devoted to training, education, and operator certification, NPCC estimates that it will expend 1 percent of its resources on this activity.

Funding Sources and Requirements — Explanation of Increase (Decrease)

Funding Sources (Other than ERO Assessments)

- U.S. Penalty Sanctions remitted from 7/1/13 through 6/30/14 reduce U.S. LSE designee assessments for 2015.

Personnel Expenses

- NPCC anticipates no need to hire additional personnel in this program area in 2015.
- Salaries expense reflects implementation of recommendations of NPCC's Management Development and Compensation Committee, which were based on an independent compensation study.
- Benefits expense decreased due to more staff opting out of company sponsored health insurance for superior coverage through prior employer or spouse.
- Retirement expense decreased due to transition of employees formerly accruing benefits under the defined benefit plan to receiving defined contribution benefits in 2015.

Operating Expenses and Indirect Expenses

- NPCC total overhead expenses, such as office rent and office costs will be charged to the Administrative Services Programs and then reallocated proportionately based on FTE to the programs through Indirect Expenses.

Other Non-Operating Expenses

- None

Fixed Asset Additions

- None

Training, Education, and Operator Certification Program

Funding sources and related expenses for the training, education, and operator certification section of the 2015 business plan are shown in the table below.

Statement of Activities and Capital Expenditures
2014 Budget & Projection, and 2015 Budget
Training, Education, and Operator Certification

		2014 Budget	2014 Projection	Variance 2014 Projection v 2014 Budget Over(Under)	2015 Budget	Variance 2015 Budget v 2014 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ 131,306	$ 131,306	$ -	$ 134,001	$ 2,695
	Penalty Sanctions	549	549	-	1,009	459
Total ERO Funding		**$ 131,855**	**$ 131,855**	**$ -**	**$ 135,010**	**$ 3,154**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops	64,000	64,000	-	64,000	-
	Interest	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Funding (A)		**$ 195,855**	**$ 195,855**	**$ -**	**$ 199,010**	**$ 3,154**
Expenses						
Personnel Expenses						
	Salaries	$ 17,448	$ 17,448	$ -	$ 18,460	$ 1,012
	Payroll Taxes	1,063	1,063	-	1,274	211
	Benefits	4,500	4,500	-	4,052	(448)
	Retirement Costs	4,776	4,776	-	4,436	(341)
Total Personnel Expenses		**$ 27,787**	**$ 27,787**	**$ -**	**$ 28,222**	**$ 434**
Meeting Expenses						
	Meetings	$ 135,000	$ 135,000	$ -	$ 137,000	$ 2,000
	Travel	15,000	15,000	-	15,000	-
	Conference Calls	-	-	-	-	-
Total Meeting Expenses		**$ 150,000**	**$ 150,000**	**$ -**	**$ 152,000**	**$ 2,000**
Operating Expenses						
	Consultants & Contracts	$ -	$ -	$ -	$ -	$ -
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
	Depreciation	-	-	-	-	-
Total Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	Total Direct Expenses	**$ 177,787**	**$ 177,787**	**$ -**	**$ 180,222**	**$ 2,434**
Indirect Expenses		**$ 18,965**	**$ 18,965**	**$ -**	**$ 19,154**	**$ 189**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 196,753**	**$ 196,753**	**$ -**	**$ 199,376**	**$ 2,623**
Change in Assets		**$ (897)**	**$ (897)**	**$ -**	**$ (366)**	**$ 531**
Fixed Assets						
	Depreciation	$ -	-	$ -	$ -	$ -
	Computer & Software CapEx	-	-	-	-	-
	Furniture & Fixtures CapEx	-	-	-	-	-
	Equipment CapEx	-	-	-	-	-
	Leasehold Improvements	-	-	-	-	-
	Allocation of Fixed Assets	(897)	(897)	-	(366)	531
Inc(Dec) in Fixed Assets (C)		**(897)**	**(897)**	**-**	**(366)**	**531**
TOTAL BUDGET (=B+C)		195,855	195,855	-	199,010	3,154
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ (0)**	**$ (0)**	**$ -**	**$ (0)**	**$ 0**

Situation Awareness and Infrastructure Security Program

Situation Awareness and Infrastructure Security Program Resources (in whole dollars)	2014 Budget	2015 Budget	Increase (Decrease)
Total FTEs	3.00	3.00	0.00
Direct Expenses	$922,070	$937,689	$15,619
Indirect Expenses	$568,962	$574,629	$5,667
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	($26,920)	($10,986)	$15,935
Total Funding Requirement	$1,464,111	$1,501,332	$37,221

Program Scope and Functional Description

The Situation Awareness and Infrastructure Security Program is the combination of near real time awareness of conditions on the bulk power system with the programs necessary to increase the physical and cyber security of the electricity infrastructure, including the operation and maintenance of tools and other support services for the benefit of Reliability Coordinators and the system operators within the registered entities. Maintaining the real-time awareness of conditions on the interconnected bulk power systems by the NPCC Reliability Coordinator is critical to maintaining reliable operation within NPCC, including the communication of information concerning system conditions and abnormal events among the neighboring system operators responsible for the reliable operation of the bulk power systems. When a disturbance does occur, it is critical to use the event as a learning opportunity and provide a forum for the active coordination of reliability and operation among the NPCC Reliability Coordinator areas and neighboring NERC Regions to enhance the reliability of the interconnected bulk power system through the lessons to be learned which can be gleaned from such an event.

Event Analysis Program[50]

NERC and the industry pursue three avenues in the analysis of a disturbance: the identification of lessons to be learned, a formal cause code analysis and a review of applicable standards.

The Event Analysis Program recognizes that many events which occur on the bulk power system beyond the routine reporting requirements previously in place can have varying levels of significance to the electric system, providing otherwise unrealized lessons to be learned from these events and the trending of such events to identify possible reliability concerns. By integrating a "bottom-up" approach to a disturbance review within the framework of the NERC Event Analysis Program, consistency, comparability, flexibility and timeliness in the event analysis process will be promoted by NPCC, the registered entities and NERC in a collaborative initiative. Upon the identification of an event, the goal of the Event Analysis Program is to:

- identify what transpired;
- categorize the event within the NERC Event Analysis Program;

[50] In support of ERO Goal 4.b. Events and system performance are consistently analyzed for sequence, cause, and remediation to identify reliability risks and trends and lessons learned.

- establish the sequence of events;
- understand the essential root causes of the event;
- identify recommendations or corrective actions; and
- develop and disseminate to the industry, lessons to be learned so that the operational reliability of the bulk power system can be further enhanced.

In assessing any system event, it is recognized that, if the timely dissemination of lessons learned from an event or disturbance is to be realized, any potential compliance implications associated with an event must be addressed and dismissed. Throughout an event analysis effort, to make this process successful and complete, and to solidify the "bottom-up" approach, registered entities are encouraged to establish a liaison between the event analysis and compliance functions internal to the registered entity during the event analysis process. This serves to facilitate the development of a registered entity compliance self-assessment report which will perform a sufficiency review of the reliability standards deemed applicable to the event, assisting in the self-reporting of possible violations should any be discovered.

To complete this effort, the entity, the Region and NERC staff collaborate to assess the NERC Event Analysis Report and perform a formal cause code analysis, identifying a root cause and complementing any lessons learned gathered from the disturbance.

The adoption by NERC of the Event Analysis Program brings clarity and certainty about what system events are relevant to analyze and to what level of detail, targeting potential vulnerabilities to the reliability of the bulk power system for detailed and in depth analysis; only concise and succinct reviews are desired for more minor events. It also delineates the expectations of roles and responsibilities of the registered entities, NPCC and NERC in a uniform review of system disturbances by the industry, and, ultimately, the program promotes the timely development and dissemination of valuable lessons learned to the industry. The identification and tracking of emerging common elements in system events will further distinguish trends which may be of concern to reliability. By rigorously pursuing the lesser events on the system and learning from these disturbances, the larger event can be avoided or mitigated.

NPCC Staff works step-by-step with the registered entity in the total event analysis process, permitting the entity to assume the primary role in the initial analysis, the development of lessons learned which may benefit the industry and the Standards sufficiency review.

NERC Alert Process[51]

NPCC Staff works with the registered entities to appropriately respond to the NERC Alert system, a process through which notifications of potential threats to electric reliability are disseminated to the industry with the expectations placed on the entity proportional to the severity of the Alert being issued.

NPCC Staff is also working closely with the NERC Staff to incorporate greater efficiencies, industry input and precision into the NERC proposal for a more streamlined NERC Alert process which can disseminate critical information to the appropriate Subject Matter Expert within the organization who can promptly act on the alert.

[51] In support of ERO Goal 4.c. ERO supports industry situational awareness and cybersecurity preparedness and provides independent reliability information to policy makers.

Operational Status[52]

On an ongoing, but non-real time basis, NPCC monitors the operational status of the bulk power system and coordinates normal and pre-emergency communication, awareness and assistance in addition to the same during an emergency among the Reliability Coordinators within NPCC and its neighboring RCs: the New Brunswick Power Corporation, Hydro-Québec TransÉnergie, the ISO New England, Inc., the New York ISO and the Independent Electricity System Operator in Ontario. The industry is notified of significant bulk power system events that have occurred in one Reliability Coordinator Area, and which have the potential to impact reliability in other NPCC Reliability Coordinator Areas or Regions external to NPCC. These events include contingencies on the bulk power system, potential shortfalls of operating reserve, operating problems, potential security threats and potential threats or disruptions to the cyber systems.

The "NPCC Emergency Preparedness Conference Call Procedures" provide a mechanism that enables the Reliability Coordinator in NPCC, and, as circumstances may require, their counterparts in neighboring Regions, to rapidly communicate the status of current operating conditions, to facilitate the procurement of assistance during emergency conditions and to identify potential physical or cyber threats to the system.

Items of particular concern that can be discussed during the calls may include, but are not limited to, the following: anticipated weather conditions critical to the system or systems experiencing or projecting resource deficiencies; load forecast; largest first and second contingencies; potential need for emergency transfers; operating reserve requirements and expected available operating reserve capacity deficiencies; potential fuel shortages or potential fuel supply disruptions which could lead to energy shortfalls; identified or projected voltage conditions; status of short term transactions; additional capability available within four hours and additional capability available within twelve hours; generator outages; significant transmission outages; expected transfer limits and limiting elements; anticipated implementation of NERC Transmission Loading Relief (TLR); changes in the status of relay protection systems; arming of special protection systems not normally armed; and/or the application of abnormal operating procedures.

NPCC has also established a daily conference call to serve as a complement to the NPCC Emergency Preparedness Conference Call. The participants of the call are the Reliability Coordinators within NPCC and its neighboring RCs, the Midwest ISO and PJM. The conference call is implemented through a bridge, the initiation of the call quickly ringing all pre-selected telephones simultaneously. The goal of the call is to alert all Reliability Coordinators of emerging problems. If no system difficulties are anticipated for the day, no unnecessary information is to be discussed. Subjects for discussion are limited to credible events which could impact the ability of an entity to serve its load and meet its operating reserve obligations or would impose a burden to the interconnection, including the following: Projected Load; Adverse Weather; Operating Reserve; Generation; Transmission; and Sabotage. If conditions worsen in the course of the day, the NPCC Emergency Preparedness Conference Call will be implemented.

NPCC monitors the status of the bulk power system through the NERC Situational Awareness-FERC, NERC, Regions (SAFNR) initiative, a near real-time operating display for the United States portion of the Reliability Coordinators footprints of North America. Transmission voltage

[52] In support of ERO Goal 4.c. ERO supports industry situational awareness and cybersecurity preparedness and provides independent reliability information to policy makers.

levels of 230 kV and above are displayed, and the tool provides the ability to "drill down" to detailed bus information.

To ensure the capability for continued voice communications among NPCC and its Reliability Coordinators, a satellite telephone network was also established, and it is tested on a monthly basis. This back-up communications system will function in the event of a collapse of the Public Switched Telephone Network (PSTN), and cross-border voice communications can still be maintained among the Canadian Reliability Coordinators of NPCC and the Reliability Coordinators in the United States.

Critical Infrastructure Objectives

NPCC's critical infrastructure objectives are defined within the scope of the NPCC Task Force on Infrastructure Security & Technology, (TFIST) and include, but are not confined to:

- Providing a forum for NPCC review of proposed and posted documents from the NERC Critical Infrastructure Protection Committee (CIPC)
- Representing and advocating NPCC's position in the activities of NERC groups involved in the development and/or implementation of physical and cyber security

NPCC's 2015 critical infrastructure goals and objectives, as identified by the 2014-2015 Work Plan of the Task Force on Infrastructure Security and Technology include, but are not confined to:

- Oversee the implementation of version 5 of the CIP Standards
- Monitor the Homeland Security Information Network (HSIN), ES-ISAC, Critical Information Protection Information Sharing (CIPIS), NERC Alerts and Canadian Information Sharing and share information with CO-8[53]
- Coordinate Cyber Protection activities, discussions and hold workshops as may be required to maintain Cyber Security of BES Cyber Assets.[54]
- Provide continued support and participation in NERC's Critical Infrastructure Protection Committee (CIPC)[55]
- Review and submit comments on NERC proposed Reliability Standards, modified Reliability Standards, proposed Guidelines and modified Guidelines related to Infrastructure Security and Technology
- Keep current on all governmental agencies regarding applicable security recommendations and requirements, and other applicable security and reliability recommendations and keep the RCC and its committees appropriately informed, e.g. Sector Specific Plan.
- Develop and maintain levels of expertise in those areas of concern to the task force through activities such as periodic workshop presentations, seminars, and meetings, open to the general NPCC membership[56].
- Regarding the Cross Border Emergency Telecommunications recommendation
    - Continue to annually report to RCC on this testing

[53] In support of ERO Goal 5.b. Issue and track security recommendations to protect the bulk power system (related to 5.a.ii.)

[54] In support of ERO Goal 1. b. Facilitate smooth transition of new standards (e.g., CIP Version 5); and ERO Goal 3.a. Initiate compliance phase-in learning periods for new standards

[55] In support of ERO Goal 5.a. Manage risk control initiatives to be completed by ERO and coordinate other initiatives with industry (e.g., relay misoperations, situational awareness, human error, cyber attack)

[56] In support of ERO Goal 5.b. Expand the use and value of security threat and vulnerability information sharing, analytics, and analysis

    - Continue to support CO-8's monthly testing
- Assess the telecommunications industry's desire to convert Frame Relay customers to Multiprotocol Label Switching (MPLS) and potentially provide recommendations to RCC

System Operations Security Objectives

NPCC's system operations security objectives are defined within the scope of the NPCC Task Force on Coordination of Operation (TFCO) and include, but are not confined to:

- Coordinating inter-Regional pre-emergency actions in the event of a threat to the security of the Northeastern North American bulk power supply system[57]
- Assisting in the development of real time operating tools assuring cyber security concerns are addressed[58]

NPCC's 2015 operational situation awareness goals and objectives, as identified by the 2014-2015 Work Plan of the NPCC Task Force on Coordination of Operation (TFCO) include, but are not confined to:

- Continue to monitor the reliable implementation of version 5 of the Cyber Standards.[59]
- Work directly with applicable NPCC Task Forces to provide an in depth assessment of Lessons Learned unique to the NPCC members and NPCC criteria.

2015 Key Assumptions

- The monitoring of Lessons Learned will be a major focus of NERC in 2015.
- Critical infrastructure protection will fully integrate the requirements of version 5 of the Cyber Standards in 2015.

2015 Goals and Key Deliverables

- Continue to monitor the reliable implementation of version 5 of the Cyber Standards.
- Work directly with applicable NPCC Task Forces to provide an in depth assessment of Lessons Learned unique to the NPCC members and NPCC criteria.
- Establish a unique NPCC Event Analysis web site to post NPCC Lessons Learned.
- Contribute to the reduction of Category 3 events and no Category 4 or 5 events in NPCC- by disseminating to the RCC compiled information on NPCC Region specific, as well as industry wide, event related causal analysis and analysis of Lessons Learned.[60]

Based on the portion of professional/technical staff time and other resources devoted to situation awareness and infrastructure security, NPCC estimates that it will expend 10 percent of its resources on this activity.

[57] In support of ERO Goal 5.b.Issue and track security recommendations to protect the bulk power system (related to 5.a.ii.)

[58] In support of ERO Goal 5.a. Manage risk control initiatives to be completed by ERO and coordinate other initiatives with industry (e.g., relay misoperations, situational awareness, human error, cyber attack)

[59] In support of ERO Goal 5.a. Manage risk control initiatives to be completed by ERO and coordinate other initiatives with industry (e.g., relay misoperations, situational awareness, human error, cyber attack)

[60] In support of ERO Goal 4.b. Provide lessons learned and recommendations from events and identified risks

Funding Sources and Requirements — Explanation of Increase (Decrease)

Funding Sources (Other than ERO Assessments)

- U.S. Penalty Sanctions remitted from 7/1/13 through 6/30/14 reduce U.S. LSE designee assessments for 2015.

Personnel Expenses

- NPCC anticipates no need to hire additional personnel in this program area in 2015.
- Salaries expense relects implementation of recommendations of NPCC's Management Development and Compensation Committee, which were based on an independent compensation study.
- Benefits expense decreased due to more staff opting out of company sponsored health insurance for superior coverage through prior employer or spouse.
- Retirement expense decreased due to transition of employees formerly accruing benefits under the defined benefit plan to receiving defined contribution benefits in 2015.

Operating Expenses and Indirect Expenses

- NPCC total overhead expenses, such as office rent and office costs will be charged to the Administrative Services Programs and then reallocated proportionately based on FTE to the programs through Indirect Expenses.
- Consultants and contracts expense increase in support of NPCC's efforts to assess and improve system frequency and generator governor response.

Other Non-Operating Expenses

- None

Fixed Asset Additions

- None

Situation Awareness and Infrastructure Security Program

Funding sources and related expenses for the situation awareness and infrastructure security section of the 2015 business plan are shown in the table below.

Statement of Activities and Capital Expenditures
2014 Budget & Projection, and 2015 Budget
Situation Awareness and Infrastructure Security

	2014 Budget	2014 Projection	Variance 2014 Projection v 2014 Budget Over(Under)	2015 Budget	Variance 2015 Budget v 2014 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 1,447,636	$ 1,447,636	$ -	$ 1,471,074	$ 23,438
Penalty Sanctions	16,475	16,475	-	30,258	13,783
Total ERO Funding	**$ 1,464,111**	**$ 1,464,111**	**$ -**	**$ 1,501,332**	**$ 37,221**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	-	-	-	-	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 1,464,111**	**$ 1,464,111**	**$ -**	**$ 1,501,332**	**$ 37,221**
Expenses					
Personnel Expenses					
Salaries	$ 522,672	$ 522,672	$ -	$ 541,258	$ 18,586
Payroll Taxes	32,961	32,961	-	32,811	(150)
Benefits	88,851	88,851	-	80,801	(8,049)
Retirement Costs	117,586	117,586	-	107,819	(9,767)
Total Personnel Expenses	**$ 762,070**	**$ 762,070**	**$ -**	**$ 762,689**	**$ 619**
Meeting Expenses					
Meetings	$ 25,000	$ 25,000	$ -	$ 15,000	$ (10,000)
Travel	60,000	60,000	-	60,000	-
Conference Calls	-	-	-	-	-
Total Meeting Expenses	**$ 85,000**	**$ 85,000**	**$ -**	**$ 75,000**	**$ (10,000)**
Operating Expenses					
Consultants & Contracts	$ 75,000	$ 75,000	$ -	$ 100,000	$ 25,000
Office Rent	-	-	-	-	-
Office Costs	-	-	-	-	-
Professional Services	-	-	-	-	-
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Depreciation	-	-	-	-	-
Total Operating Expenses	**$ 75,000**	**$ 75,000**	**$ -**	**$ 100,000**	**$ 25,000**
Total Direct Expenses	**$ 922,070**	**$ 922,070**	**$ -**	**$ 937,689**	**$ 15,619**
Indirect Expenses	**$ 568,962**	**$ 568,962**	**$ -**	**$ 574,629**	**$ 5,667**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 1,491,031**	**$ 1,491,031**	**$ -**	**$ 1,512,318**	**$ 21,286**
Change in Assets	**$ (26,920)**	**$ (26,920)**	**$ -**	**$ (10,986)**	**$ 15,935**
Fixed Assets					
Depreciation	$ -	-	$ -	$ -	$ -
Computer & Software CapEx	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	(26,920)	(26,920)	-	(10,986)	15,935
Inc(Dec) in Fixed Assets (C)	**(26,920)**	**(26,920)**	**-**	**(10,986)**	**15,935**
TOTAL BUDGET (=B+C)	1,464,111	1,464,111	-	1,501,332	37,221
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**$ (0)**	**$ (0)**	**$ -**	**$ (0)**	**$ (0)**

Administrative Services

Administrative Services Program Resources (in whole dollars)	2014 Budget	2015 Budget	Increase (Decrease)
Total FTEs	9.00	9.00	0.00
Total Direct Expenses	$5,689,616	$5,746,287	$56,671
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	$0	$0	$0
Less: Other Funding Sources	$0	$0	$0
Total Allocation to Regional Entity Division Programs as Indirect Expenses	($5,283,757)	($5,336,385)	($52,629)
Total Allocation to Criteria Services Division Programs as Indirect Expenses	($405,859)	($409,902)	($4,043)
Funding Requirement for Working Capital and Operating Reserves	($300,126)	($355,161)	($55,035)

Program Scope and Functional Description

Administrative services support the previously identified five program areas of: reliability standards; compliance monitoring and enforcement and organization registration and certification; training, education, and operator certification; reliability assessment and performance analysis; and situation awareness and infrastructure security. Administrative services consist of: technical committees and members' forums; general and administrative; legal and regulatory; information technology; human resources; and finance and accounting.

Methodology for Allocation of Administrative Services Expenses to Programs

NPCC total overhead expenses, such as office rent and office costs, will be charged to the Administrative Services Programs and then reallocated proportionately based on FTE to the programs through Indirect Expenses.

Funding Sources and Requirements — Explanation of Increase (Decrease)

Personnel Expenses

- NPCC anticipates no need to hire additional personnel in this program area in 2015.
- Salaries expense reflect implementation of recommendations of NPCC's Management Development and Compensation Committee, which were based on an independent compensation study.
- Benefits expense decreased due to more staff opting out of company sponsored health insurance for superior coverage through prior employer or spouse.
- Retirement expense decreased due to transition of employees formerly accruing benefits under the defined benefit plan to receiving defined contribution benefits in 2015.

Administrative Services

Funding sources and related expenses for the Administrative Services section of the 2015 business plan are shown in the table below.

Statement of Activities and Capital Expenditures 2014 Budget & Projection, and 2015 Budget ADMINISTRATIVE SERVICES						
		2014 Budget	2014 Projection	Variance 2014 Projection v 2014 Budget Over(Under)	2015 Budget	Variance 2015 Budget v 2014 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ (300,126)	$ (300,126)	$ -	$ (355,161)	$ (55,035)
	Penalty Sanctions	-	-	-	-	-
Total ERO Funding		**$ (300,126)**	**$ (300,126)**	**$ -**	**$ (355,161)**	**$ (55,035)**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops	-	-	-	-	-
	Interest	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Funding (A)		**$ (300,126)**	**$ (300,126)**	**$ -**	**$ (355,161)**	**$ (55,035)**
Expenses						
Personnel Expenses						
	Salaries	$ 1,676,735	$ 1,676,735	$ -	$ 1,769,318	$ 92,583
	Payroll Taxes	96,083	96,083	-	97,804	1,722
	Benefits	442,256	442,256	-	402,307	(39,949)
	Retirement Costs	425,270	425,270	-	435,638	10,368
Total Personnel Expenses		**$ 2,640,344**	**$ 2,640,344**	**$ -**	**$ 2,705,068**	**$ 64,724**
Meeting Expenses						
	Meetings	$ 110,000	$ 110,000	$ -	$ 120,000	$ 10,000
	Travel	155,000	155,000	-	155,000	-
	Conference Calls	77,000	77,000	-	45,000	(32,000)
Total Meeting Expenses		**$ 342,000**	**$ 342,000**	**$ -**	**$ 320,000**	**$ (22,000)**
Operating Expenses						
	Consultants & Contracts	$ 150,000	$ 150,000	$ -	$ 124,000	$ (26,000)
	Office Rent	737,272	737,272	-	751,500	14,228
	Office Costs	523,500	523,500	-	578,700	55,200
	Professional Services	966,500	966,500	-	1,025,000	58,500
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	80,000	80,000	-	40,000	(40,000)
	Depreciation	250,000	250,000	-	202,019	(47,981)
Total Operating Expenses		**$ 2,707,272**	**$ 2,707,272**	**$ -**	**$ 2,721,219**	**$ 13,947**
	Total Direct Expenses	**$ 5,689,616**	**$ 5,689,616**	**$ -**	**$ 5,746,287**	**$ 56,671**
Indirect Expenses		**$ (5,689,616)**	**$ (5,689,616)**	**$ -**	**$ (5,746,287)**	**$ (56,671)**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ -**	**$ -**	**$ -**	**$ (0)**	**$ (0)**
Change in Assets		**$ (300,126)**	**$ (300,126)**	**$ -**	**$ (355,161)**	**$ (55,035)**
Fixed Assets						
	Depreciation	(250,000)	(250,000)	$ -	(202,019)	$ 47,981
	Computer & Software CapEx	-	-	-	100,000	100,000
	Furniture & Fixtures CapEx	-	-	-	-	-
	Equipment CapEx	-	-	-	-	-
	Leasehold Improvements	-	-	-	-	-
	Allocation of Fixed Assets	250,000	250,000	-	102,019	(147,981)
Inc(Dec) in Fixed Assets (C)		**-**	**-**	**-**	**-**	**-**
TOTAL BUDGET (=B+C)		-	-	-	(0)	(0)
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ (300,126)**	**$ (300,126)**	**$ -**	**$ (355,161)**	**$ (55,035)**

Technical Committees and Member Forums

Technical Committees and Members Forum Program Resources (in whole dollars)	2014 Budget	2015 Budget	Increase (Decrease)
Total FTEs	0.50	0.50	0.00
Total Direct Expenses	$75,711	$73,779	($1,932)
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	$0	$0	$0
Working Capital Requirement	$0	$0	$0

Program Scope and Functional Description

The success of the NPCC programs depends on the active and direct volunteerism and participation of its members. The stakeholders are the source of expertise in the industry. To promote the reliable and efficient operation of the interconnected bulk power systems in Northeastern North America, NPCC invites high level policy makers from Federal, Provincial and State regulatory and/or governmental authorities and senior executives within NPCC and NERC to identify and discuss emerging issues related to the reliability of the NPCC Region.

2015 Key Assumptions

- NPCC's standing committee and subgroup structure for effective stakeholder involvement will continue in 2015
- NPCC will continue to utilize methods to encourage active involvement in its Regional programs that require less stakeholder travel and face-to-face meetings, as the economy improves in 2015
- NPCC will continue to invest in technology and innovation to allow efficient collaboration on technical issues related to reliability

2015 Goals and Key Deliverables

The 2015 NPCC General Meeting provides an opportunity for NPCC Members to meet high level policy makers from Federal, Provincial and State regulatory and/or governmental authorities and senior NERC and NPCC executives to discuss topics related to the reliable planning and operation of the power system, including consideration of emerging reliability, critical infrastructure and environmental issues.

2015 Public Information Committee Goals and Objectives

The objective of the NPCC Public Information Committee is to highlight and summarize NPCC activities and accomplishments in the past year, disseminate and coordinate the appropriate release of information to the media, respond to related requests for information, and coordinate with related NPCC Area, NERC media and public information activities. Activities anticipated for include, but are not limited to:

- Conducting the Media Event – release of the Summer 2015 NPCC Reliability Assessment

- Participation in NERC Regional communication initiatives:
    - Regional communications teleconferences as required
    - Coordination of Emergency or Blackout communications plans
    - Coordination with other NERC activities as required (i.e., situation awareness, event analysis, reliability assessments, etc.)

Funding Sources and Requirements — Explanation of Increase (Decrease)

Funding Sources (Other than ERO Assessments)

- Not applicable

Operating Expenses and Indirect Expenses

- NPCC total overhead expenses, such as office rent and office costs will be charged to the Administrative Services Programs and then reallocated proportionately based on FTE to the programs through Indirect Expenses.

Other Non-Operating Expenses

- None

Fixed Asset Additions

- None

General and Administrative

General and Administrative Program Resources (in whole dollars)	2014 Budget	2015 Budget	Increase (Decrease)
Total FTEs	2.50	2.50	0.00
Total Direct Expenses	$3,293,356	$3,209,290	($84,066)
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	$0	$0	$0
Working Capital Requirement	($300,126)	($355,161)	($55,035)

Program Scope and Functional Description

The NPCC general and administrative function provides executive management of the corporation, management of NPCC office, and other administrative support programs.

NPCC total overhead expenses, such as office rent and office costs, will be charged to the Administrative Services Programs and then reallocated proportionately based on FTE to the programs through Indirect Expenses.

Funding Requirements — Explanation of Increase (Decrease)

Funding Sources (Other than ERO Assessments)

- Not applicable

Operating Expenses and Indirect Expenses

- NPCC total overhead expenses, such as office rent and office costs will be charged to the Administrative Services Programs and then reallocated proportionately based on FTE to the programs through Indirect Expenses.

Other Non-Operating Expenses

- None

Fixed Asset Additions

- None

Legal and Regulatory

Legal and Regulatory Program Resources (in whole dollars)	2014 Budget	2015 Budget	Increase (Decrease)
Total FTEs	1.00	1.00	0.00
Total Direct Expenses	$621,004	$628,183	$7,179
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	$0	$0	$0
Working Capital Requirement	$0	$0	$0

Program Scope and Functional Description

NPCC's professional legal services provide counsel to the President and CEO, Board of Directors, Vice President and COO, Treasurer and staff on a wide range of legal and regulatory matters including legislation, corporate law, code of conduct, confidentiality, governance, employment law, tax matters, contract law and other areas affecting NPCC. Regulatory counsel provides legal advice to advance significant corporate policy and strategic planning initiatives and also provides legal support to other program areas on matters arising in connection with the performance of NPCC's delegated functions. Regulatory counsel drafts agreements and pleadings and provides interpretations of relevant statutes, regulations, court opinions, and regulatory decisions of FERC, state agencies and provincial authorities. Outside counsel, as necessary, reviews items filed with the governmental agencies for legal sufficiency, maintains relationships with U.S. and Canadian jurisdictions and provides contract review.

Funding Sources (Other than ERO Assessments)

- Not applicable

Operating Expenses and Indirect Expenses

- NPCC total overhead expenses, such as office rent and office costs will be charged to the Administrative Services Programs and then reallocated proportionately based on FTE to the programs through Indirect Expenses.

Other Non-Operating Expenses

- None

Fixed Asset Additions

- None

Information Technology

Information Technology Program Resources (in whole dollars)	2014 Budget	2015 Budget	Increase (Decrease)
Total FTEs	3.00	3.00	0.00
Total Direct Expenses	$1,037,624	$1,111,674	$74,050
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	$0	$0	$0
Working Capital Requirement	$0	$0	$0

Program Scope and Functional Description

NPCC's Information Technology services ensure information assets and the environment in which they operate are secure and in conformance to NPCC IT Policies and Procedures. NPCC maintains an offsite backup server for continuity of essential operations in the event that its primary location is unavailable.

2015 Key Assumptions

- Continue to develop and maintain the compliance portal through collaboration with other Regions and NERC (CUG).
- Achieve greater consistency with the other Regions and NERC by participating in the NERC IT Steering Group (ITSG) and deriving the efficiencies and cost savings which may result from the projects of this group.[61]
    - The ERO EMG identifies and prioritizes ERO-wide applications to be developed under a PMO housed at NERC. The NERC IT budget does not supplant the Regional Entities' need for IT expenditures for specific regional projects, but to the extent that agreed-upon ERO Enterprise applications provide greater efficiencies, there should not be any unnecessary, redundant expenditures at the regional level.
- Support the Event Analysis program through continued participation in the tools used for the tracking and analysis of system events.[62]
- Support the Bulk Electric System Exception Process "BEP" to enable and facilitate tracking and processing of exceptions submitted.[63] Maintenance of the BESNET support services such as updates, patching, coordinating issues with NERC.
- Support Cyber Security Reviews done by compliance to provide advisory role during those reviews.

[61] ERO Goal 7.b. Develop test and deploy ERO enterprise applications, platform and database

[62] ERO Goal 6.b. Evaluate event disturbances using phasor measurements and other methods to assess sufficiency of data and models;
ERO Goal 4.b. Provide lessons learned and recommendations from events and identified risks;
ERO Goal 4.b. Merge event driven databases and cause codes into one (e.g., event analysis, TADS, GADS, relay mis-operations)

[63] ERO Goal 2.a. Develop and implement BES exception process.

2015 Goals and Key Deliverables

Responsibilities encompass a variety of complex technical, administrative, and supervisory work in the development, installation, and maintenance of information technology systems. IT goals include, but are not limited to:

- Create an information security program and environment aimed at reducing breach of security risks
- Determine long-term software and systems needs and hardware acquisitions
- Develop and implement information security standards and procedures
- Ensure all information systems are functional and secure, and that all applications running on those systems meet business requirements for performance, availability, and security
- Plan and implement organization-wide information systems, services, and network facilities, including local area networks, wide-area networks, and peripheral systems
- Provide outreach and education to NPCC members in IT best practices
- Continually improve Disaster Recovery policies and practices to ensure continuity of service

Funding Sources and Requirements — Explanation of Increase (Decrease)

Funding Sources (Other than ERO Assessments)

- Not applicable

Operating Expenses and Indirect Expenses

- NPCC total overhead expenses, such as office rent and office costs will be charged to the Administrative Services Programs and then reallocated proportionately based on FTE to the programs through Indirect Expenses.

Other Non-Operating Expenses

- None

Fixed Asset Additions

- None

Human Resources

Human Resources Program Resources (in whole dollars)	2014 Budget	2015 Budget	Increase (Decrease)
Total FTEs	1.00	1.00	0.00
Total Direct Expenses	$178,931	$183,817	$4,886
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	$0	$0	$0
Working Capital Requirement	$0	$0	$0

Program Scope and Functional Description

NPCC has assembled an exceptional team of highly qualified employees to carry out the activities of NPCC. The human resources function, in adherence with applicable federal and state laws, designs, plans, and implements human resources policies and procedures, including staffing, compensation, benefits, employee relations, and training and development.

An enhanced employee time tracking system was implemented in 2013 based on FERC audit recommendations. Employee time tracking and reporting is also handled by the human resources program area.

Funding Sources (Other than ERO Assessments)

- Not applicable

Operating Expenses and Indirect Expenses

- NPCC total overhead expenses, such as office rent and office costs will be charged to the Administrative Services Programs and then reallocated proportionately based on FTE to the programs through Indirect Expenses.

Other Non-Operating Expenses

- None

Fixed Asset Additions

- None

Accounting and Finance

Accounting and Finance Program Resources (in whole dollars)	2014 Budget	2015 Budget	Increase (Decrease)
Total FTEs	1.00	1.00	0.00
Total Direct Expenses	$482,991	$494,544	$11,554
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	$0	$0	$0
Working Capital Requirement	$0	$0	$0

Program Scope and Functional Description

The accounting and finance function directs the overall financial plans and accounting practices of the organization; oversees treasury, accounting, budget, tax, and audit activities; and oversees financial and accounting system controls and standards. NPCC uses a CPA firm to prepare its unaudited statements of activities and financial statements for quarterly reviews. Independent audits have identified this system as a best practice.

2015 Goals and Key Deliverables

The objectives are to provide or obtain the financial and accounting services for NPCC and coordinate with NERC requirements:

- Utilize the NERC System of Accounts for consistency
- Utilize an accrual method of accounting for consistency with NERC in methodology
- Cash Management
- Budget Development using the NERC budget template formats
- Forecasts and Projections
- Alignment of NPCC Committees, Task Forces and Working Groups with the programs
- Payroll and expense administration
- Preparation of unaudited Quarterly Financial Statements
- IRS Reporting
- Annual Independent Audit initiated by the Regional Entity

Funding Sources and Requirements — Explanation of Increase (Decrease)

Funding Sources (Other than ERO Assessments)

- Not applicable

Operating Expenses and Indirect Expenses

- NPCC total overhead expenses, such as office rent and office costs will be charged to the Administrative Services Programs and then reallocated proportionately based on FTE to the programs through Indirect Expenses.

Other Non-Operating Expenses

- None

Fixed Asset Additions

- None

Regional Entity Assessment Analysis

In the area of assessments there are distinct funding mechanisms as outlined in the following table. For the Regional Entity division, the North American Electric Reliability Corporation (NERC) will assess load serving entities (LSEs) or their designees (within NPCC the designees are the Balancing Authority Areas (BAAs) for New York, New England, New Brunswick, Nova Scotia, Ontario and Québec) based upon 2013 proportional Net Energy for Load (NEL) and other specific program area funding arrangements and make quarterly remittances to the Regional Entity on or about the 15th day of January, April, July and October. For funding associated with the criteria services division, the Independent System Operators/Balancing Authority Areas (ISO/BAAs) will be assessed by NPCC for their proportional share of the divisional budget based upon 2012 NEL within the Region. Non ISO/BAA Full Members will be assessed no membership fee.

NPCC Cost Allocation Methodology

The accompanying table provides information regarding cost allocation for both the Regional Entity division and the criteria services division of NPCC, including the details associated with the funding of the Compliance Program within the RE division. For purposes of determining assessments to support NPCC's resource requirements, costs are allocated among the BAAs within NPCC as the designees for the load-serving-entities in New York, New England, Ontario, Québec, New Brunswick and Nova Scotia (Column A-1).

In order to reflect and respect the international membership and nature of NPCC, the compliance responsibilities and authorities within the U.S., and the specific compliance responsibilities within each of the Canadian provinces within NPCC, the attendant costs of portions of the compliance program differ among the areas within the Regional Entity. Within the U.S. portion of NPCC all costs attributable to delegated (statutory) functions performed by NPCC, including all compliance functions, are assessed based on a NEL allocation. Within the Canadian portion of NPCC those costs attributable to compliance functions performed by NPCC on behalf of provincial governmental and/or regulatory authorities are allocated consistent with the unique Memoranda of Understanding or Agreements that have been entered into for those provinces. To address these different compliance regimes, NPCC developed a composite cost allocation methodology that allocates compliance costs on a fair and equitable basis within the Regional Entity.

As an initial step of that methodology, the NEL for each of the BAAs and their relative percentage to the NPCC total NEL is calculated for the most recent year for which data is available, the second previous year (Columns B-1 and C-1, respectively). In order to establish the RE division funding requirements for each balancing authority area on a NEL basis for all programs except for compliance (Column F-1), the proposed expenses and fixed assets of all other programs are calculated (Column D-1) and the adjustment for the RE division cash reserve requirement is identified (Column E-1). Any penalty monies received from NPCC registered entities within the U.S. prior to June 30th of the year preceding the business plan and budget year are then allocated among the NPCC program areas based on their FTE ratio and between the U.S. BAAs based on their relative NELs (Columns B-1a., C-1a. and G-1, respectively). Consistent with each of the Canadian provincial MOUs and agreements, all penalty monies resulting from compliance actions within Canada, if any, would remain within the applicable province. The total budgeted fees for NPCC workshop participation are indicated as a credit

(Column H-1), with the resultant addition being the RE division assessment, without the compliance program costs, calculated on a NEL basis (Column I-1).

In accordance with the *NPCC Amended and Restated Bylaws* the CS division proposed expenses and fixed assets of all programs are calculated (Column J-1) and the adjustment for the CS division cash reserve requirement is identified (Column K-1), with the resultant addition being the CS division funding requirement and assessment, calculated on a NEL basis (Column L-1).

For costs associated with the RE division compliance program, NPCC's allocation methodology apportions X% of the costs for the program, attributed to CORC Fundamentals (CF), between the BAAs in the United States and Canada on a NEL basis (Column B-2).

Audits and Investigations (AI) related costs, representing X% of the costs of the compliance program, are allocated between U.S. and Canadian BAAs in NPCC, and among the Canadian provinces, using an audit-based methodology (Columns C-2a., C-2c., and D-2b., respectively). The audit-based methodology incorporates relative costs based on categories of compliance audits which are reflective of their size and complexity, as well as the differing compliance program implementation models that are utilized in NPCC due to the international nature of the Regional Entity. The portion allocated to the U.S. BAAs in NPCC is calculated using the audit-based methodology, and this amount is then re-allocated between the New York and New England BAAs based on their relative NEL (Columns C-2b. and D-2a.).

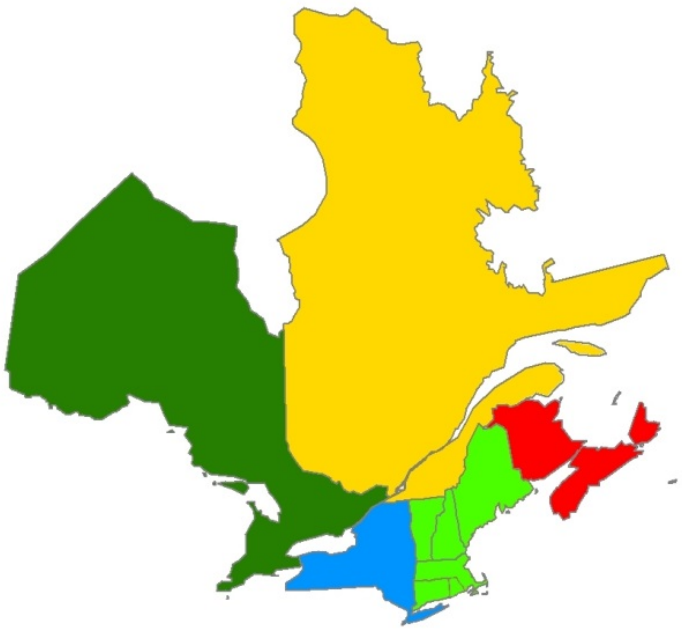
The remaining X% of the costs of the compliance program represent Mitigation and Enforcement (ME) related costs and are allocated between U.S. and Canadian BAAs in NPCC, and among the Canadian provinces, using an enforcement activity based methodology, (Columns E-2a., E-2c., and F-2b., respectively). Based on historical data, NPCC reviewed each BAAs percentage of violations, mitigation plans and settlement agreements to determine each BAAs total average percentage of enforcement activities. The portion allocated to the U.S. BAAs in NPCC is calculated using the enforcement activity based methodology, and this amount is then re-allocated between the New York and New England BAAs based on their relative NEL (Columns E-2b. and F-2a.).

Any penalty monies received from NPCC registered entities within the U.S. by June 30th of the year preceding the business plan and budget year are then allocated among the NPCC program areas based on their FTE ratio and between the U.S. BAAs based on their relative NELs, and then added to the total compliance program expenses and fixed assets to yield a total compliance program assessment (Columns C-1a., H-2, G-2 and I-2, respectively).

Finally, the total RE division funding requirements and assessments by BAA are tabulated and the total funding requirements and assessments for NPCC, both the RE and CS divisions, are combined (Column M).

Table to be Inserted

Section B – Supplemental Financial Information
2015 Business Plan and Budget



Section B — Supplemental Financial Information

Reserve Balance

Table B-1 – Reserve Balance

Working Capital and Operating Reserve Analysis 2014-2015
REGIONAL ENTITY DIVISION

	Total Reserve	Operating Reserve	Working Capital
Beginning Total Reserve, December 31, 2013	**5,245,194**	4,013,698	1,231,496
Plus: 2014 ERO Funding (from LSEs or designees)	13,611,880	13,611,880	0
Plus: 2014 Other funding sources	217,000	217,000	0
Less: 2014 Projected expenses & capital expenditures	(14,129,006)	(14,129,006)	0
Projected Total Reserve, December 31, 2014	**4,945,068**	**3,713,572**	**1,231,496**
Desired Total Reserve, December 31, 2015 [1]	**4,589,907**	3,358,411 [2]	1,231,496 [3]
31.06% of Total Regional Entity Budget of $14,778,539			
Less: Projected Working Capital and Operating Reserve, December 31, 2014	(4,945,068)	(3,713,572)	(1,231,496)
Increase(decrease) in assessments to achieve desired Total Reserve	**(355,161)**	(355,161)	0

2015 Expenses and Capital Expenditures	14,778,539
Less: Penalty Sanctions [4]	(281,000)
Less: Other Funding Sources	(64,000)
Adjustment to achieve desired Total Reserve balance	(355,161)
2015 Assessment	**14,078,378**

[1] Total Reserve within a range of 16.67% - 33.33% of Budget.
[2] Operating Reserve within a range from 8.33% to 25.00% of Budget. $3,358,411 represents 22.72% of the 2015 budget of $14,778,539
[3] Working Capital equal to 8.33% of Budget. $1,231,496 represents 8.33% of the 2015 budget of $14,778,539
[4] Represents collections prior to June 30, 2014.

Explanation of Changes in Reserve Policy from Prior Year

On October 29, 2013 NPCC's Board of Directors approved management's proposed Working Capital and Operating Reserve Policy. The policy calls for a range between 8.33% (30 days) and 25.00% (90 days) rather than the specific required level of Operating Reserves of 8.33%. This range will allow for more stability in Assessments. The Working Capital required balance remains unchanged at 8.33% (30 days).

Breakdown by Statement of Activity Sections

The following detailed schedules are in support of the Regional Entity division Statement of Activities on page 13 of the 2015 Business Plan and Budget. All significant variances have been disclosed by program area in the preceding pages.

Penalty Sanctions

U.S. penalty monies received prior to June 30, 2014 are to be used to offset assessments in the 2015 Budget, as documented in the NERC Policy – Accounting, Financial Statement, and Budgetary Treatment of Penalties Imposed and Received for Violations of Reliability Standard. Penalty monies received from July 1, 2014 through June 30, 2015 will be used to offset U.S. load serving entity designee assessments in the 2016 Budget.

All penalties received prior to June 30, 2014 are detailed below, including date received and the penalty amount.

Allocation Method: U.S. penalty sanctions received have been allocated to the following Regional Entity division programs to reduce assessments: Reliability Standards; Compliance Monitoring & Enforcement and Organization Registration & Certification; Reliability Assessments and Performance Analysis; Training, Education and Operator Certification; and Situation Awareness and Infrastructure Security. U.S. penalty sanctions are allocated based upon the number of FTEs in the Program divided by the aggregate total FTEs in the Programs receiving the allocation.

Table B-2 – Penalty Sanctions

Penalty Sanctions Received Prior to June 30, 2014	Date Received	Amount Received
Penalty Payment 1	7/5/2013	$ 50,000.00
Penalty Payment 2	7/5/2013	$ 10,000.00
Penalty Payment 3	7/5/2013	$ 30,000.00
Penalty Payment 4	7/5/2013	$ 25,000.00
Penalty Payment 5	9/4/2013	$ 7,000.00
Penalty Payment 6	10/16/2013	$ 25,000.00
Penalty Payment 7	11/1/2013	$ 5,000.00
Penalty Payment 8	1/8/2014	$ 25,000.00
Penalty Payment 9	3/6/2014	$ 14,000.00
Penalty Payment 10	4/30/2014	$ 90,000.00
Total Penalties Received		**$ 281,000.00**

Table B-3 – Supplemental Funding

Outside Funding Breakdown By Program (excluding ERO Assessments & Penalty Sanctions)	Budget 2014	Projection 2014	Budget 2015	Variance 2015 Budget v 2014 Budget
Reliability Standards				
Total	$ -	$ -	$ -	$ -
Compliance Monitoring, Enforcement & Org. Registration				
	$ -	$ -	$ -	$ -
	-	-	-	-
Total	$ -	$ -	$ -	$ -
Reliability Assessment and Performance Analysis				
	$ -	$ -	$ -	$ -
	-	-	-	-
Total	$ -	$ -	$ -	$ -
Training and Education				
Workshops	$ 64,000	$ 64,000	$ 64,000	$ -
Total	$ 64,000	$ 64,000	$ 64,000	$ -
Situation Awareness and Infrastructure Security				
	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -
Technical Committees and Member Forums				
	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -
Administrative Services Programs				
	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -
Total Outside Funding	$ 64,000	$ 64,000	$ 64,000	$ -

Explanation of Significant Variances –2015 Budget versus 2014 Budget

- NPCC assumed no interest income because of continuing low market interest rates.

Table B-4 – Personnel Expenses

Personnel Expenses	Budget 2014	Projection 2014	Budget 2015	Variance 2015 Budget v 2014 Budget	Variance %
Salaries					
Salary	$ 5,886,227	$ 5,886,227	$ 6,175,425	$ 289,198	4.9%
Employment Agency Fees	$ 15,000	$ 15,000	$ 10,000	$ (5,000)	-33.3%
Temporary Office Services	$ 10,000	$ 10,000	$ 10,000	$ -	0.0%
Total Salaries	$ 5,911,227	$ 5,911,227	$ 6,195,425	$ 284,198	4.8%
Total Payroll Taxes	$ 384,311	$ 384,311	$ 387,209	$ 2,898	0.8%
Benefits					
Education Reimbursement	$ -	$ -	$ 10,000	$ 10,000	-
Training and Seminars	$ 36,123	$ 36,123	$ 36,123	$ -	0.0%
Medical Insurance	$ 915,306	$ 915,306	$ 720,337	$ (194,969)	-21.3%
Life-LTD-STD Insurance	$ 63,552	$ 63,552	$ 64,366	$ 815	1.3%
Worker's Compensation	$ 14,700	$ 14,700	$ 14,700	$ -	0.0%
Vacation	$ 400,580	$ 400,580	$ 410,868	$ 10,288	2.6%
Relocation	$ -	$ -	$ -	$ -	-
Total Benefits	$ 1,430,261	$ 1,430,261	$ 1,256,395	$ (173,866)	-12.2%
Retirement					
Pension Contribution	$ 590,892	$ 590,892	$ 353,723	$ (237,169)	-40.1%
Employee Savings Plan	$ 478,469	$ 478,469	$ 644,290	$ 165,821	34.7%
Savings Admin	$ 32,000	$ 32,000	$ 32,000	$ -	0.0%
Deferred Compensation	$ 23,000	$ 23,000	$ 60,000	$ 37,000	160.9%
Total Retirement	$ 1,124,361	$ 1,124,361	$ 1,090,013	$ (34,348)	-3.1%
Total Personnel Costs	**$ 8,850,160**	**$ 8,850,160**	**$ 8,929,041**	**$ 78,881**	**0.9%**
FTEs	36.86	36.86	36.86	-	0.0%
Cost per FTE					
Salaries	$ 160,370	$ 160,370	$ 168,080	$ 7,710	4.8%
Payroll Taxes	$ 10,426	$ 10,426	$ 10,505	$ 79	0.8%
Benefits	$ 38,803	$ 38,803	$ 34,086	$ (4,717)	-12.2%
Retirement	$ 30,504	$ 30,504	$ 29,572	$ (932)	-3.1%
Total Cost per FTE	**$ 240,102**	**$ 240,102**	**$ 242,242**	**$ 2,140**	**0.9%**

Explanation of Significant Variances –2015 Budget versus 2014 Budget

- The increase in Salaries reflects an overall general wage increase of 3%, at risk (variable incentives) compensation at less than 100% of program levels, and implementation of recommendations of NPCC's Management Development and Compensation Committee, which were based on an independent compensation study.
- Benefits expense decreased due to more staff opting out of company sponsored health insurance for superior coverage through prior employer or spouse.
- Pension contribution decreased while employee savings plan increased due to transition of employees formerly accruing benefits under the defined benefit plan to receiving defined contribution benefits in 2015.
- The decrease in Employment Agency Fee is due to no planned staff additions in 2015. Agencies would be used only to fill positions vacated during the year.
- A 2% vacancy factor is assumed based on historical vacancy trends.

Table B-5 – Consultants and Contracts

Consultants	Budget 2014	Projection 2014	Budget 2015	Variance 2015 Budget v 2014 Budget	Variance %
Consultants					
Reliability Standards	$ -	$ -	$ -	$ -	-
Compliance Enforcement and Organization Registration and Certification	$ 10,000	$ 10,000	$ 15,000	$ 5,000	50.0%
Reliability Assessment and Performance Analysis	$ -	$ -	$ -	$ -	-
Training and Education	$ -	$ -	$ -	$ -	-
Situation Awareness and Infrastructure Security	$ -	$ -	$ -	$ -	-
Member Forums	$ -	$ -	$ -	$ -	-
General and Administrative	$ 50,000	$ 50,000	$ 35,000	$ (15,000)	-30.0%
Legal and Regulatory	$ -	$ -	$ -	$ -	-
Information Technology	$ -	$ -	$ -	$ -	-
Human Resources	$ -	$ -	$ -	$ -	-
Accounting and Finance	$ -	$ -	$ -	$ -	-
Consultants Total	**$ 60,000**	**$ 60,000**	**$ 50,000**	**$ (10,000)**	**-16.7%**

Contracts	Budget 2014	Projection 2014	Budget 2015	Variance 2015 Budget v 2014 Budget	Variance %
Reliability Standards	$ 30,000	$ 30,000	$ 25,000	$ (5,000)	-16.7%
Compliance Enforcement and Organization Registration and Certification	$ 1,384,433	$ 1,384,433	$ 1,713,000	$ 328,567	23.7%
Reliability Assessment and Performance Analysis	$ 275,000	$ 275,000	$ 365,000	$ 90,000	32.7%
Training and Education	$ -	$ -	$ -	$ -	-
Situation Awareness and Infrastructure Security	$ 75,000	$ 75,000	$ 100,000	$ 25,000	33.3%
Member Forums	$ -	$ -	$ -	$ -	-
General and Administrative	$ 90,000	$ 90,000	$ 82,000	$ (8,000)	-8.9%
Legal and Regulatory	$ -	$ -	$ -	$ -	-
Information Technology	$ -	$ -	$ -	$ -	-
Human Resources	$ -	$ -	$ -	$ -	-
Accounting and Finance	$ 10,000	$ 10,000	$ 7,000	$ (3,000)	-30.0%
Contracts Total	**$ 1,864,433**	**$ 1,864,433**	**$ 2,292,000**	**$ 427,567**	**22.9%**
Total Consultants and Contracts	**$ 1,924,433**	**$ 1,924,433**	**$ 2,342,000**	**$ 417,567**	**21.7%**

Explanation of Significant Variances –2015 Budget versus 2014 Budget

- Compliance Enforcement and Organization Registration and Certification consultant and contractor costs increased due to increased workload related to the initial implementation of the RAI, incorporating Risk Assessment and Internal Control assessment. Without this one time ramp up in RAI endeavors for 2015, contractor costs would have remained relatively flat. These joint ERO Enterprise initiatives are intended to benefit the registered entities, Regional Entities and NERC. With a risk and performance based assessment of each registered entity, audits will transition to a periodicity more reflective of the risk profile of the entity such that some audits will be more in-depth while others may have a reduced scope which will require less independent contractor resources.

- Reliability Assessment and Performance Analysis contracts expense increase is related to implementation of the revised BES definition.

Table B-6 – Office Rent

Office Rent	Budget 2014	Projection 2014	Budget 2015	Variance 2015 Budget v 2014 Budget	Variance %
Office Rent	$ 654,772	$ 654,772	$ 645,000	$ (9,772)	-1.5%
Utilities	$ 35,000	$ 35,000	$ 40,000	$ 5,000	14.3%
Maintenance	$ 15,000	$ 15,000	$ 22,000	$ 7,000	46.7%
Security	$ 2,500	$ 2,500	$ 2,500	$ -	0.0%
Real Estate Taxes	$ 30,000	$ 30,000	$ 42,000	$ 12,000	40.0%
Total Office Rent	**$ 737,273**	**$ 737,273**	**$ 751,501**	**$ 14,228**	**1.9%**

Table B-7 – Office Costs

Office Costs	Budget 2014	Projection 2014	Budget 2015	Variance 2015 Budget v 2014 Budget	Variance %
Telephone	$ 110,000	$ 110,000	$ 110,000	$ -	0.0%
Internet Expense	$ 80,000	$ 80,000	$ 80,000	$ -	0.0%
Office Supplies	$ 35,000	$ 35,000	$ 36,000	$ 1,000	2.9%
Computer Supplies and Maintenance	$ 213,000	$ 213,000	$ 260,000	$ 47,000	22.1%
Subscriptions & Publications	$ 13,000	$ 13,000	$ 13,500	$ 500	3.8%
Dues	$ 4,000	$ 4,000	$ 4,000	$ -	0.0%
Postage	$ 1,500	$ 1,500	$ 1,200	$ (300)	-20.0%
Express Shipping	$ 10,000	$ 10,000	$ 10,000	$ -	0.0%
Copying	$ 25,000	$ 25,000	$ 25,000	$ -	0.0%
Reports	$ -	$ -	$ 5,000	$ 5,000	-
Stationary and Office Forms	$ 5,000	$ 5,000	$ 3,000	$ (2,000)	-40.0%
Equipment Repair/Service Contracts	$ 10,000	$ 10,000	$ 8,000	$ (2,000)	-20.0%
Bank Charges	$ 30,000	$ 30,000	$ 23,000	$ (7,000)	-23.3%
Sales and Use Tax	$ -	$ -	$ -	$ -	-
Merchant Credit Card Fees	$ -	$ -	$ -	$ -	-
Presentation and Publicity	$ -	$ -	$ -	$ -	-
Total Office Costs	**$ 536,500**	**$ 536,499**	**$ 578,700**	**$ 42,200**	**7.9%**

Explanation of Significant Variances –2015 Budget versus 2014 Budget

- Computer Supplies and Maintenance expense is based on contracts currently in place and historical actual expense.

Table B-8 - Professional Services

Professional Services	Budget 2014	Projection 2014	Budget 2015	Variance 2015 Budget v 2014 Budget	Variance %
BOT Fee	$ 280,000	$ 280,000	$ 325,000	$ 45,000	16.1%
BOT Search Fee	$ -	$ -	$ -	$ -	-
Legal - Reorganization	$ -	$ -	$ -	$ -	-
Accounting & Auditing Fees	$ 300,000	$ 300,000	$ 310,000	$ 10,000	3.3%
Legal Fees - Other	$ 350,000	$ 350,000	$ 350,000	$ -	0.0%
Insurance - Commercial	$ 36,500	$ 36,500	$ 40,000	$ 3,500	9.6%
Total Services	**$ 966,500**	**$ 966,501**	**$ 1,025,000**	**$ 58,500**	**6.1%**

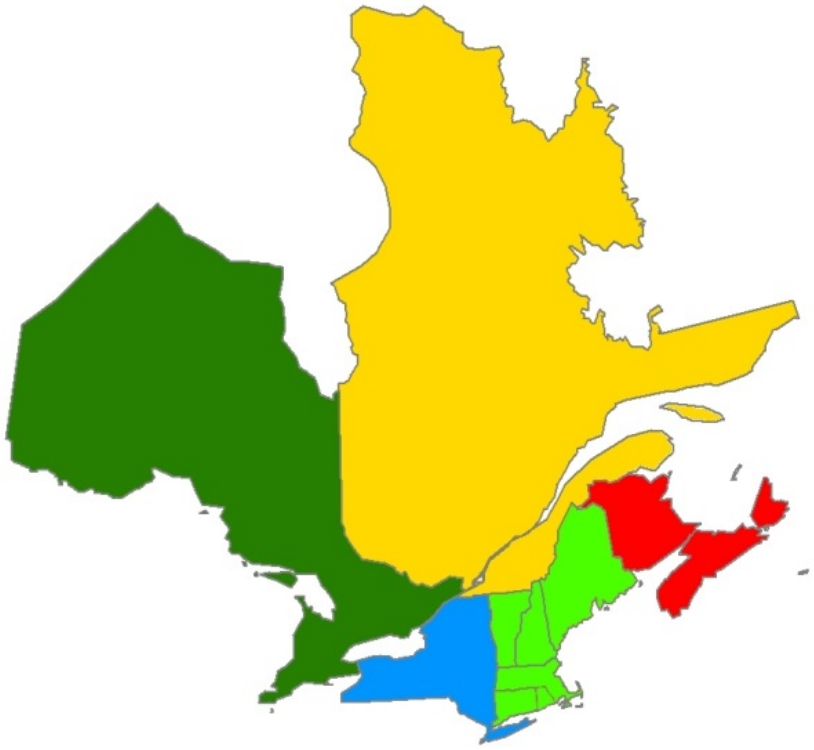
Table B-9 – Other Non-Operating Expenses

Other Non-Operating Expenses	Budget 2014	Projection 2014	Budget 2015	Variance 2015 Budget v 2014 Budget	Variance %
Interest Expense	$ -	$ -	$ -	$ -	-
Office Relocation	$ -	$ -	$ -	$ -	-
Total Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**-**

Table B-10 – 2016 and 2017 Projections

Table to be Inserted

Section C – Criteria Services Division Activities
2015 Business Plan and Budget



Section C —2014 Criteria Services Division Business Plan and Budget

Criteria Services Division (in whole dollars)	2014 Budget	2015 Budget	Increase (Decrease)
Total FTEs	2.14	2.14	0.00
Total Direct Expenses	$683,240	$729,550	$46,310
Total Indirect Expenses	$405,859	$409,902	$4,043
Other Non-Operating Expenses	$0	$0	$0
Working Capital and Operating Reserves Requirement	($75,391)	($94,220)	($18,829)
Inc(Dec) in Fixed Assets	($24,000)	($10,011)	$13,989
Funding Requirement	$989,708	$1,035,221	$45,513

NPCC Regionally-Specific Criteria Services Background

NPCC Criteria Services division activities are based on the development, maintenance and promulgation of Regionally-specific more stringent criteria as well as criteria establishing resource adequacy requirements within the Region. These criteria contain requirements which are more stringent and more specific than the existing NERC Reliability Standards requirements. These criteria require continual evaluation to ensure they are "not inconsistent with" any NERC reliability standards.

Membership and Governance

Full members are subject to compliance with Regionally-specific criteria, in addition to continent-wide Reliability Standards, and receive criteria-related services from the Criteria Services division.

Full Members, aside from those who perform the Balancing Authority function, are not assessed an annual membership fee. Those that perform Balancing Authority functions are assessed and remit a proportional net energy for load share of expenses for criteria services. NPCC would also directly assign criteria service division costs to a Balancing Authority Area or entity, where significant costs are incurred for that Balancing Authority Area. The funding for NPCC's Criteria Services division is approved by the NPCC Board of Directors.

Criteria Services Division Functional Scope

Through its Criteria Services division, NPCC promotes the reliable and efficient operation of the international, interconnected bulk power systems in Northeastern North America through the establishment of Regionally-specific criteria, and monitoring and enforcement of compliance with such criteria.

NPCC provides Full Members with Regional reliability assurance services, and acts as the vehicle through which States and Provinces can fulfill their political mandates, with respect to resource adequacy, as well as overseeing the Northeastern North American electric infrastructure.

Major 2015 Assumptions and Cost Impacts

The Criteria Services division services are expected to remain stable throughout 2015 when compared to the Regional Entity division.

- The Criteria Compliance Enforcement Program (CCEP) review and evaluation process has matured and been enhanced after its inception in 2012. Criteria Compliance submittals to the CC are done as necessary.
- Past non-compliances, if any, followed the due process stated in the CCEP-1 process document and proper resolution/enforcement action taken.

2015 Primary Goals and Objectives

- Review, maintain, and revise the NPCC Regional Reliability Directories to facilitate compliance assessments and ensure the Criteria portions of the Directories are "not inconsistent" with, nor duplicative with, the approved and effective NERC Standards.
- The criteria services division and CCEP Working Group (reporting to the Compliance Committee) will work with the various Task Forces to develop Criteria Compliance Reporting Forms for additional NPCC Directories to ensure that the more stringent or Regionally-specific criteria is being met.
- The criteria services division and CCEP working group will work with TFCO, TFCP, TFSS, and TFSP to review criteria and measures within each specific NPCC Directory to identify and develop them into specific reporting forms for approval.
- Review impact of Bulk Electric System definition on Directory and Criteria content and compliance reporting.
- Review impact of Sector or NPCC organizational changes on the Directory and Criteria review, enforcement and arbitration processes
- Assist Legal with preparation of revised Directories for Regulatory filings with the individual Provinces in accordance with their respective Memorandum of Understandings (MOUs) as well as the State of New York Public Service Commission
- Facilitate any requested interpretations for NPCC Criteria with the necessary subject matter experts and identify potential opportunities for clarifications of the Criteria.

NPCC Reliability Directory Maintenance and Development

The NPCC Regional Reliability Directories were developed to demonstrate that the NPCC more stringent criteria are not inconsistent with the NERC Reliability Standards as mandated by the NERC Rules of Procedure. The Directory project was also undertaken to remove any redundancies with the NERC Reliability Standards and to clearly delineate the more stringent NPCC criteria requirements. In 2013 the directories were further reviewed and revision of the directories is underway to transition the criteria language into a "requirement type" format. This further revision facilitates the NPCC Region's CCEP and ensures the continued delineation of the more stringent and more specific Regional criteria from the latest approved and effective set of NERC ERO standards.

In 2015, work will proceed with maintenance and revision of the Directories to address any future redundancies with NERC or NPCC Reliability Standards as well as the continued need for additional more stringent or specific NPCC Regional criteria requirements as new NERC Reliability Standards are developed and existing standards are revised. NPCC will continue to rely on contractors for subject matter expertise on an as-needed basis throughout 2015. The amount of Regional documents being converted into Directories and the maintenance of the Directories require subject matter expert input. In addition, changes will be necessary to bring the Phase II Directory project to completion. This project will require significant resources to translate the existing criteria language into "requirements" that are clear, concise and measurable. Also a standards template will be applied to the existing Directories to make them more consistent with the look of the standards. As NERC standards improve, the need for NPCC Directories and amount of criteria contained therein will gradually decrease over time however in the interim, significant review is necessary to ensure the criteria remain "not inconsistent with" the NERC standards as outlined in the NERC Rules of Procedure.

The following Directories will either be under revision or reviewed for further development based on a schedule set forth in the NPCC Reliability Assessment Program:

Operations and Planning Directories

Directory #1, *Basic Criteria for Design and Operation of Interconnected Power Systems*
This directory documents NPCC's Regionally-specific, more stringent criteria, and demonstrates coordination and consistency with all the existing NERC TPL, BAL, IRO, INT, MOD, TOP, PRC and VAR standards. The NPCC Task Force on Coordination of Planning will lead a multi-disciplinary working group, consisting of operations and planning subject matter experts to review and revise this directory to reflect the FERC ruling on TPL and other TOP changes.

Directory #2, *Emergency Operations*
This directory documents NPCC's Regionally-specific, more stringent criteria, and demonstrates coordination and consistency with all the existing NERC EOP and TOP standards. The NPCC Task Force on Coordination of Operation will lead this review and revision.

Directory # 3, *Maintenance Requirements for BPS Protection*
This Directory documents NPCC's Regionally-specific, more stringent criteria, and demonstrates coordination and consistency with certain applicable NERC PRC standards. The NPCC Task Force on System Protection will lead this review and revision.

Directory # 4, *BPS Protection*
This Directory documents NPCC's Regionally-specific, more stringent criteria, and demonstrates coordination and consistency with certain applicable NERC PRC standards. The NPCC Task Force on System Protection will lead this review and revision.

Directory # 5, *Operating Reserve Requirements*
This directory documents NPCC's Regionally-specific, more stringent criteria, and demonstrates coordination and consistency with all the existing applicable NERC BAL, INT, and IRO standards. The NPCC Task Force on Coordination of Operation will lead this review and revision.

Directory # 7, *Special Protection Systems*
This Directory documents NPCC's Regionally-specific, more stringent criteria for application and approval of SPS. The NPCC Task Force on System Protection will lead this review and revision.

Directory # 8 System Restoration
This Directory documents NPCC's Regionally-specific, more stringent criteria with which each applicable entity must plan for and perform power system restoration following a major or a total blackout, and demonstrates coordination and consistency with applicable NERC EOP standards. The NPCC Task Force on Coordination of Operation will lead this review and revision.

Directory # 9, *Verification of Generator Gross and Net Reactive Power Capability*
This Directory documents NPCC's Regionally-specific, more stringent criteria for verifying the Gross Reactive Power
Capability and Net Reactive Power Capability of generators or generating facilities. The NPCC Task Force on Coordination of Operation will lead this review and revision.

Directory # 11, *Disturbance Monitoring*, This directory documents NPCC's Regionally-specific, more stringent criteria, and demonstrates coordination and consistency with certain existing NERC PRC standards. The NPCC Task Force on System Protection will lead this review and revision until such time as the NPCC PRC-002-01 Disturbance Monitoring Regional Standard is adopted by FERC and the applicable governmental authorities.

Directory # 12, *UFLS Program*, This directory documents NPCC's Regionally-specific, more stringent criteria, and demonstrates coordination and consistency with certain existing NERC and NPCC developing PRC standard(s). The NPCC Task Force on System Studies will lead this review and revision until such time as the NPCC PRC-006-01 UFLS Regional Standard is approved by the NPCC membership, NERC BOT, the FERC and all the applicable governmental authorities in the Provinces of Canada within NPCC's footprint.

NPCC Criteria Compliance Background

The NPCC criteria services division promotes the reliable operation of the bulk power system through implementation of a comprehensive compliance program. The compliance program that includes monitoring, assessing and enforcing compliance with more stringent, Regionally specific NPCC Criteria requirements, is known as the NPCC Criteria Compliance and Enforcement Program (CCEP) described in process document CCEP-1. This program was developed by the criteria services division and the CCEP Working Group under the purview of the NPCC Compliance Committee. The products of this program support the various Task Forces in their assessments of the NPCC Directories in meeting their goals for the Reliability Coordinating Committee as stated in Section A of this Business Plan.

The more stringent, Regionally-specific NPCC Criteria requirements reflect the unique operational and planning aspects of the bulk power system within the NPCC Region and are included in the NPCC "A" documents and their successors, the NPCC Directories.

NPCC issues non-monetary sanctions to enforce compliance with NPCC Criteria.

- The CCEP program is described in document CCEP-1, *NPCC Criteria Compliance and Enforcement Program (CCEP) Process Document*
- The implementation plan is described in document CCEP-2, *Implementation Plan for 2011 NPCC Criteria Compliance and Enforcement Program*
- On April 5, 2011, the above became effective upon Full Member approval of CCEP-1, and CCEP-2 and retired the following
    - NPCC Criteria A-8, Reliability Compliance and Enforcement Program (RCEP)
    - NPCC Guide B-22, Guidelines for Implementation of the NPCC Inc. Compliance Program
    - NPCC Procedure C-32, Review Process for NPCC Reliability Compliance Enforcement Program
    - Each of the above have been annotated as "retired effective 4/5/11 upon Full Member approval of CCEP-1… and CCEP-2…" on the NPCC public website

The CCEP-1 document

- recognizes the applicability of NPCC's Regionally-specific, more stringent reliability criteria to the Full Members of NPCC, consistent with the *Amended and Restated ByLaws*, and respects the provisions of the several Canadian Memoranda of Understanding in the execution of the processes described
- provides a comprehensive CCEP Process Diagram showing the process of evaluating and approving Criteria Certification submittals, and additional processes and responsibilities in the event that non-compliances, disputes and sanctions arise
- describes the roles and responsibilities of Reporting Members, CC, RCC and Enforcement Panel in the compliance review and enforcement process
- describes Levels of Non-Compliance, associated non-monetary Sanctions, Lateness Policy and the Arbitration/Dispute Resolution process
- addresses Mitigation Plans for any violations under the enforcement process; and
- lists the mandatory Certification Forms to be submitted for review by the Task Forces to ensure compliance with NPCC Directories are being met

The CCEP currently requires annual submittal of Certification Forms by the Reliability Coordinators and Balancing Authorities to confirm compliance with various NPCC Directories. Currently the required Certification forms are for Directory #1- *Area Transmission Review*, Directory #8 - *Key Facility List*, Directory #9 – *Generator Real Power Verification*, Directory #10 - *Verification of Generator Gross and Net Reactive Power Capability*, and Directory #12 - *UFLS Program Requirements*. In 2014 NPCC anticipates expansion of the CCEP to include compliance assessment activities to all active Directories.

The CCEP identifies those specific NPCC Directories that are subject to monitoring, assessment and enforcement. These Directories also are subject to NPCC Criteria Compliance Audits.

The NPCC Compliance Committee (CC) has final approval of compliance assessments related to CCEP. The CCEP describes the roles and responsibilities of committees and panels used to resolve contested compliance and/or sanction or penalty determinations related to NPCC Directories.

Explanation of Significant Variances – 2015 Budget versus 2014 Budget

Personnel Expenses

- Salaries expense reflects implementation of recommendations of NPCC's Management Development and Compensation Committee, which were based on an independent compensation study.

2014 Budget and Projection and 2015 Budget Comparisons

Statement of Activities 2014 Budget & Projection, and 2015 Budget CRITERIA SERVICES DIVISION						
		2014 Budget	2014 Projection	Variance 2014 Projection v 2014 Budget Over(Under)	2015 Budget	Variance 2015 Budget v 2014 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ -	$ -	$ -	$ -	$ -
	Penalty Sanctions	-	-	-	-	-
Total ERO Funding		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	Membership Dues	989,708	989,708	-	760,033	(229,675)
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops	-	-	-	-	-
	Interest	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Funding (A)		**$ 989,708**	**$ 989,708**	**$ -**	**$ 760,033**	**$ (229,675)**
Expenses						
Personnel Expenses						
	Salaries	$ 312,166	$ 312,166	$ -	$ 369,319	$ 57,153
	Payroll Taxes	21,536	21,536	-	22,681	1,145
	Benefits	64,153	64,153	-	76,900	12,747
	Retirement Costs	129,818	129,818	-	145,639	15,821
Total Personnel Expenses		**$ 527,674**	**$ 527,674**	**$ -**	**$ 614,539**	**$ 86,866**
Meeting Expenses						
	Meetings	$ 10,000	$ 10,000	$ -	$ 10,000	$ -
	Travel	63,000	63,000	-	63,000	-
	Conference Calls	-	-	-	-	-
Total Meeting Expenses		**$ 73,000**	**$ 73,000**	**$ -**	**$ 73,000**	**$ -**
Operating Expenses						
	Consultants & Contracts	$ 55,000	$ 55,000	$ -	$ 30,000	$ (25,000)
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	3,567	3,567	-	2,000	(1,567)
	Depreciation	24,000	24,000	-	10,011	(13,989)
Total Operating Expenses		**$ 82,567**	**$ 82,567**	**$ -**	**$ 42,011**	**$ (40,556)**
	Total Direct Expenses	**$ 683,240**	**$ 683,240**	**$ -**	**$ 729,550**	**$ 46,310**
Indirect Expenses		**$ 405,859**	**$ -**	**$ -**	**$ 409,902**	**$ 4,043**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 1,089,100**	**$ 1,089,100**	**$ -**	**$ 1,139,452**	**$ 50,353**
Change in Assets		**$ (99,391)**	**$ (99,391)**	**$ -**	**$ (379,419)**	**$ (280,027)**
Fixed Assets						
	Depreciation	$ (24,000)	(24,000)	$ -	$ (10,011)	$ 13,989
	Computer & Software CapEx	-	-	-	-	-
	Furniture & Fixtures CapEx	-	-	-	-	-
	Equipment CapEx	-	-	-	-	-
	Leasehold Improvements	-	-	-	-	-
	Allocation of Fixed Assets	-	-	-	-	-
Inc(Dec) in Fixed Assets (C)		**(24,000)**	**(24,000)**	**-**	**(10,011)**	**13,989**
TOTAL BUDGET (=B+C)		1,065,100	1,065,100	-	1,129,441	64,342
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ (75,391)**	**$ (75,391)**	**$ -**	**$ (369,408)**	**$ (294,016)**

Personnel Analysis

Total FTE's by Program Area	Budget 2014	Projection 2014	Direct FTEs 2015 Budget	Shared FTEs[1] 2015 Budget	Total FTEs 2015 Budget	Change from 2014 Budget
CRITERIA SERVICES DIVISION						
Operational Programs						
Reliability Standards	1.07	1.07	1.00	0.07	1.07	0.00
Compliance Enforcement and Organization Registration and Certification	0.00	0.00	0.00	0.00	0.00	0.00
Training and Education	0.00	0.00	0.00	0.00	0.00	0.00
Reliability Assessment and Performance Analysis	1.07	1.07	1.00	0.07	1.07	0.00
Situation Awareness and Infrastructure Security	0.00	0.00	0.00	0.00	0.00	0.00
Total FTEs Operational Programs	**2.14**	**2.14**	**2.00**	**0.14**	**2.14**	**0.00**
Administrative Programs						
Member Forums	0.00	0.00	0.00	0.00	0.00	0.00
General and Administrative	0.00	0.00	0.00	0.00	0.00	0.00
Information Technology	0.00	0.00	0.00	0.00	0.00	0.00
Legal and Regulatory	0.00	0.00	0.00	0.00	0.00	0.00
Human Resources	0.00	0.00	0.00	0.00	0.00	0.00
Accounting and Finance	0.00	0.00	0.00	0.00	0.00	0.00
Total FTEs Administrative Programs	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Total FTEs	**2.14**	**2.14**	**2.00**	**0.14**	**2.14**	**0.00**

[1]A shared FTE is defined as an employee who performs both Regional Entity and Criteria Services division functions.

Reserve Analysis 2014-2015

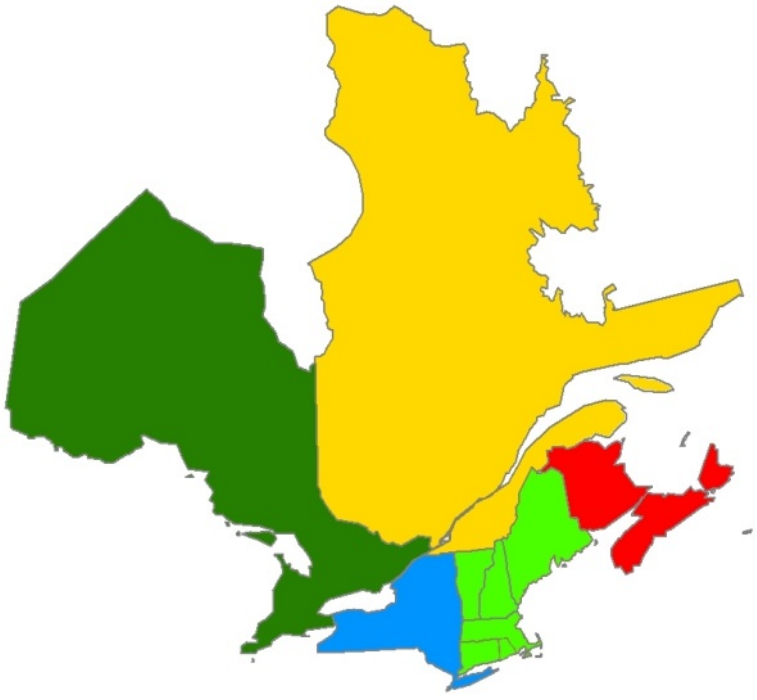
Working Capital and Operating Reserve Analysis 2014-2015			
CRITERIA SERVICES DIVISION			
	Total Reserve	**Operating Reserve**	**Working Capital**
Beginning Working Capital and Operating Reserves, December 31, 2013	816,612	727,857	88,755
2014 Non-Statutory Funding (from members)	989,708	989,708	0
2014 Other funding sources	0	0	0
Less: 2014 Projected expenses & fixed asset additions	(1,065,100)	(1,065,100)	0
Projected Working Capital, December 31, 2014	**741,220**	**652,465**	**88,755**
Desired Working Capital and Operating Reserve, December 31, 2015	**647,000**	552,884	94,116
Less: Projected Working Capital Reserve Balance December 31, 2014	(741,220)	(652,465)	(88,755)
Increase(decrease) in assessments to achieve desired Total Reserve	(94,220)	(99,581)	5,361
2015 Funding requirement for expenses and fixed asset additions	1,129,441		
Adjustment to achieve desired Working Capital and Operating Reserve balance	(94,220)		
2015 Funding and reserve requirement	1,035,221		

Explanation of Changes in Reserve Policy from Prior Year

On October 29, 2013 NPCC's Board of Directors approved management's proposed Working Capital and Operating Reserve Policy. The policy calls for a range between 8.33% (30 days) and 25.00% (90 days) rather than the specific required level of Operating Reserves of 8.33%. This range will allow for more stability in Assessments. The Working Capital required balance remains unchanged at 8.33% (30 days).

Section D – Additional Consolidated Financial Statements

2015 Business Plan and Budget



Section D

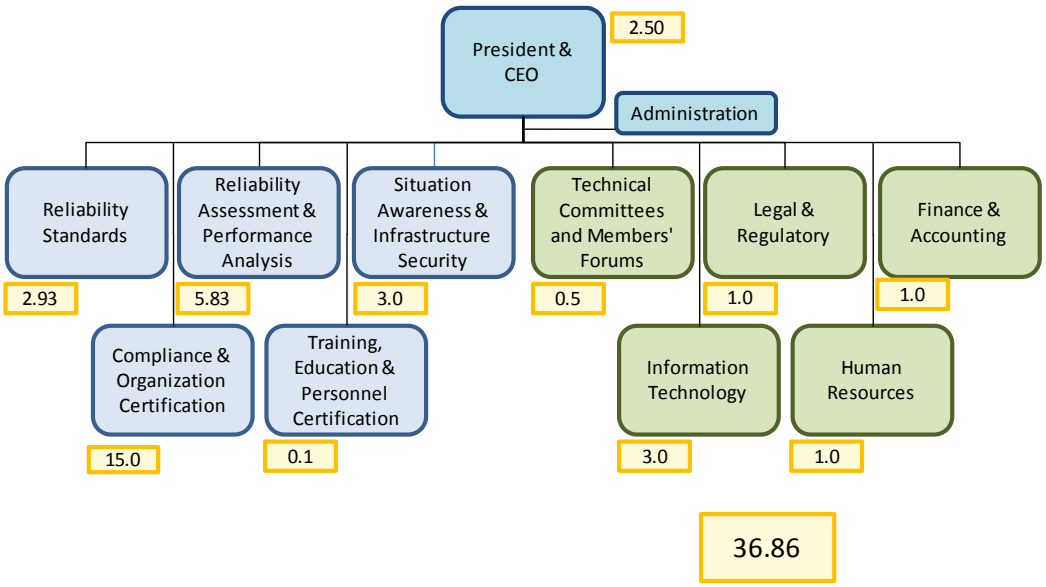
Statement of Financial Position

Table to be Inserted

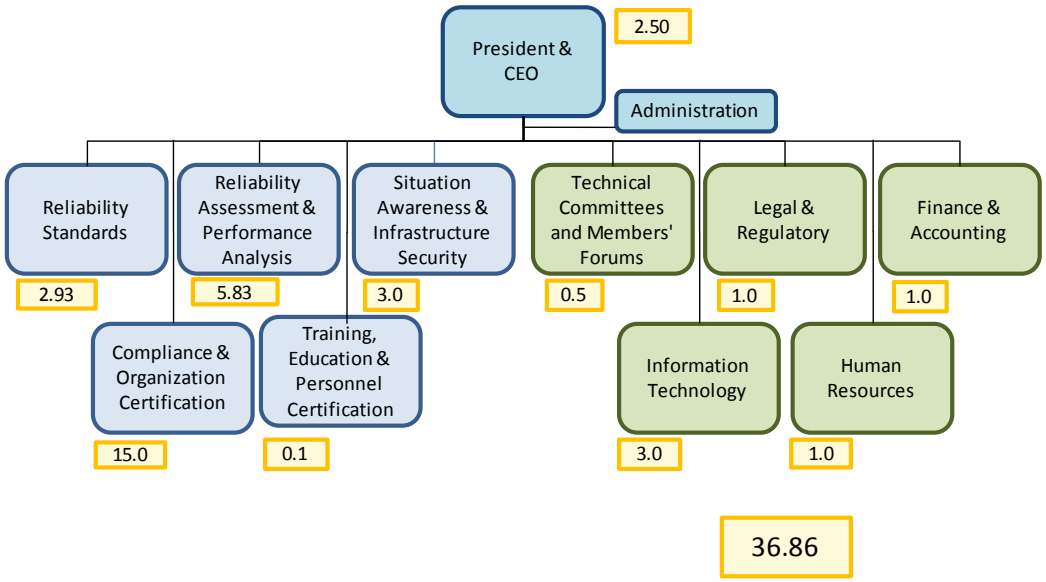
Table to be Inserted

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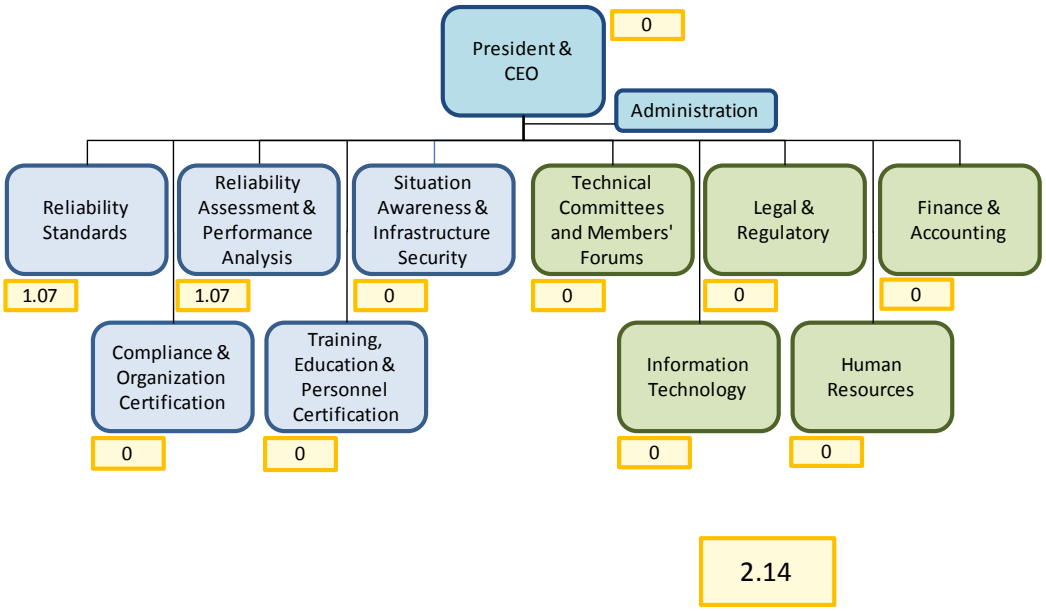
2014 Budget Staff Allocations - RE Division



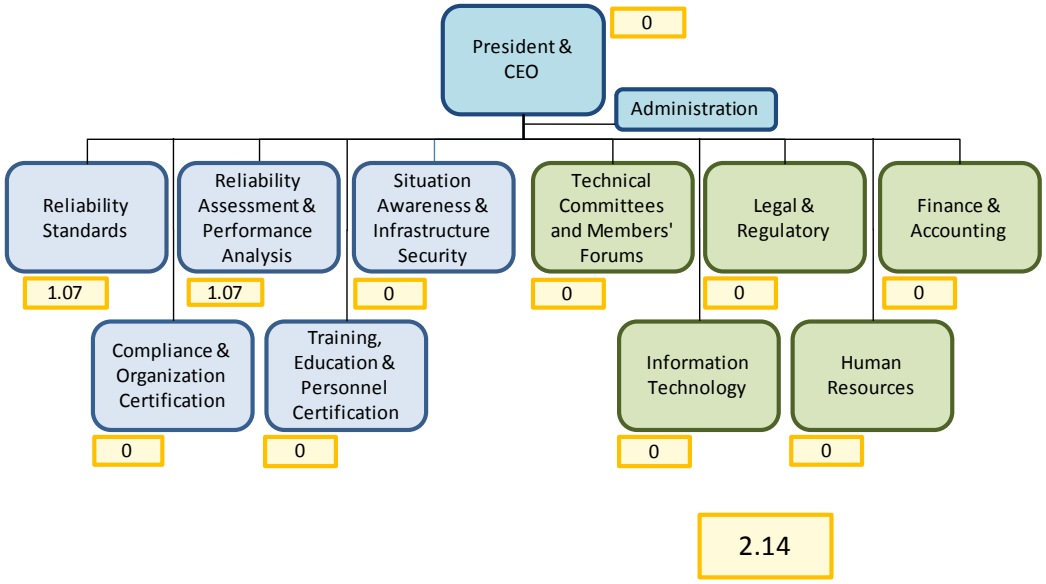
2015 Budget Staff Allocations - RE Division

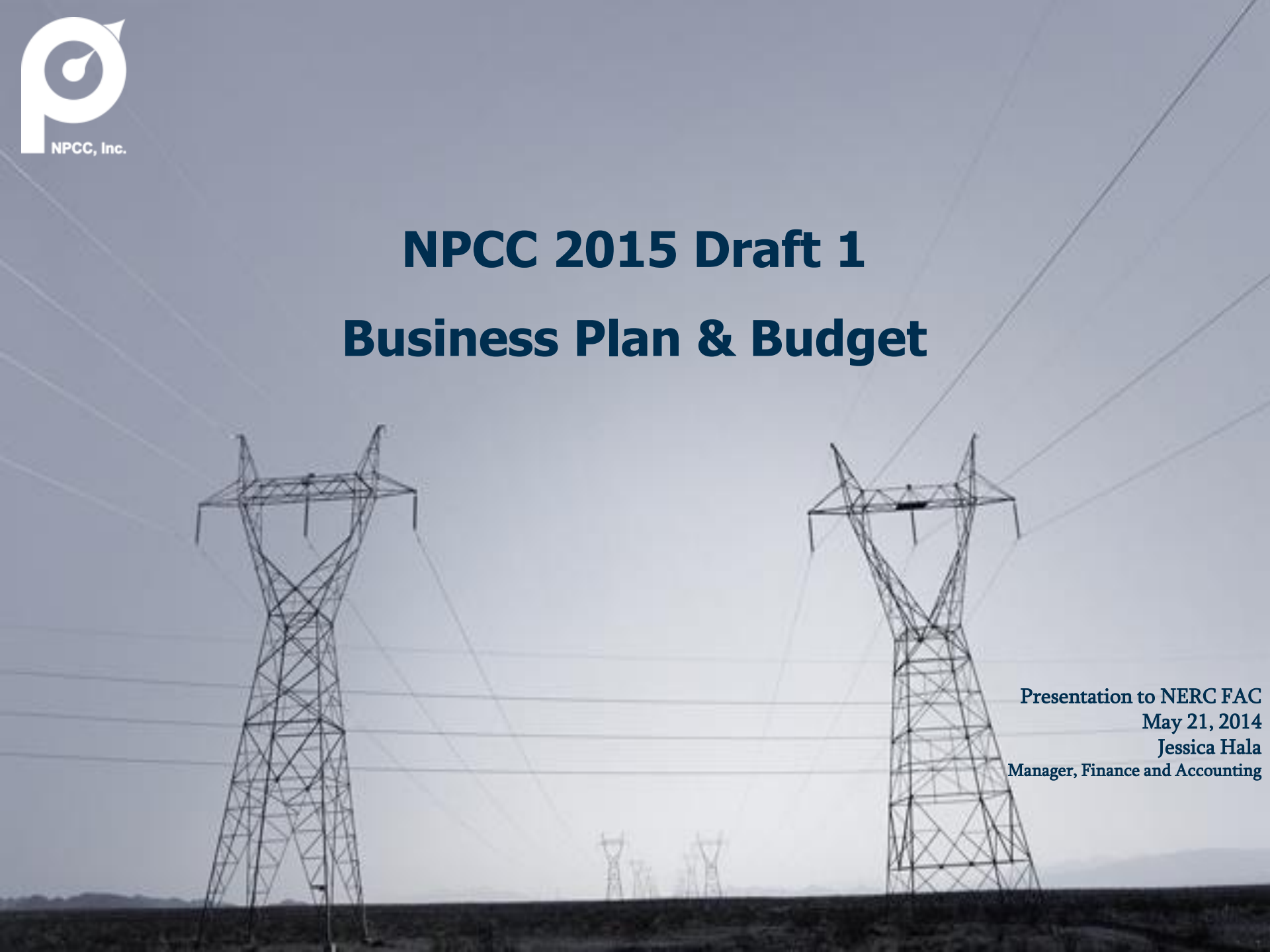


2014 Budget Staff Allocations - CS Division



2015 Budget Staff Allocations - CS Division





NPCC 2015 Draft 1

Business Plan & Budget

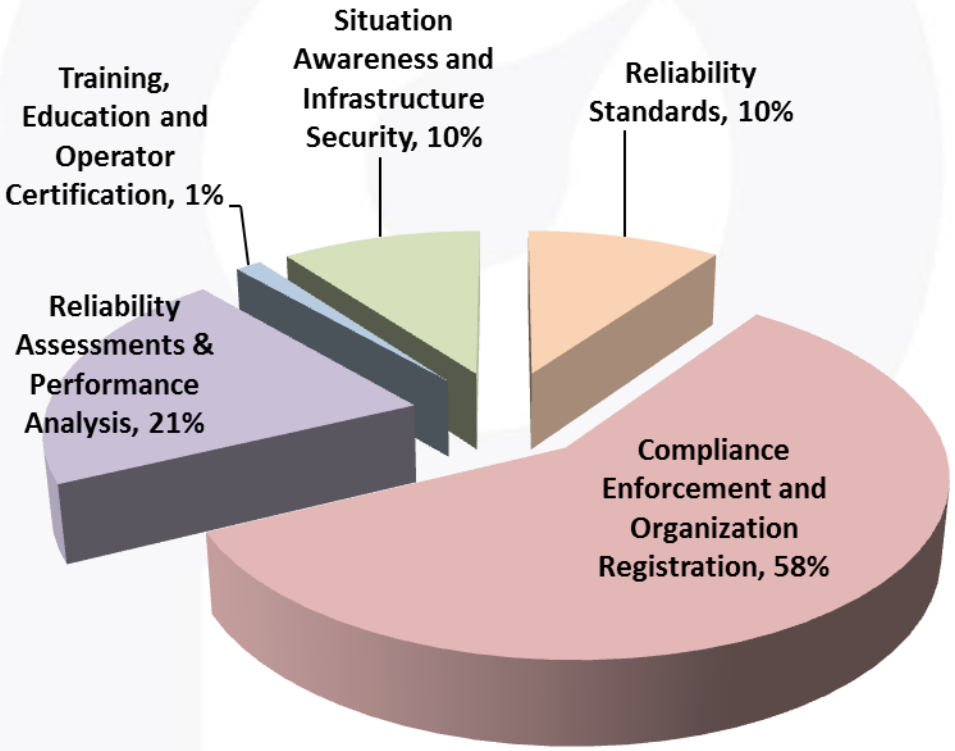
Presentation to NERC FAC
May 21, 2014

Jessica Hala
Manager, Finance and Accounting

2015 Budget Overview

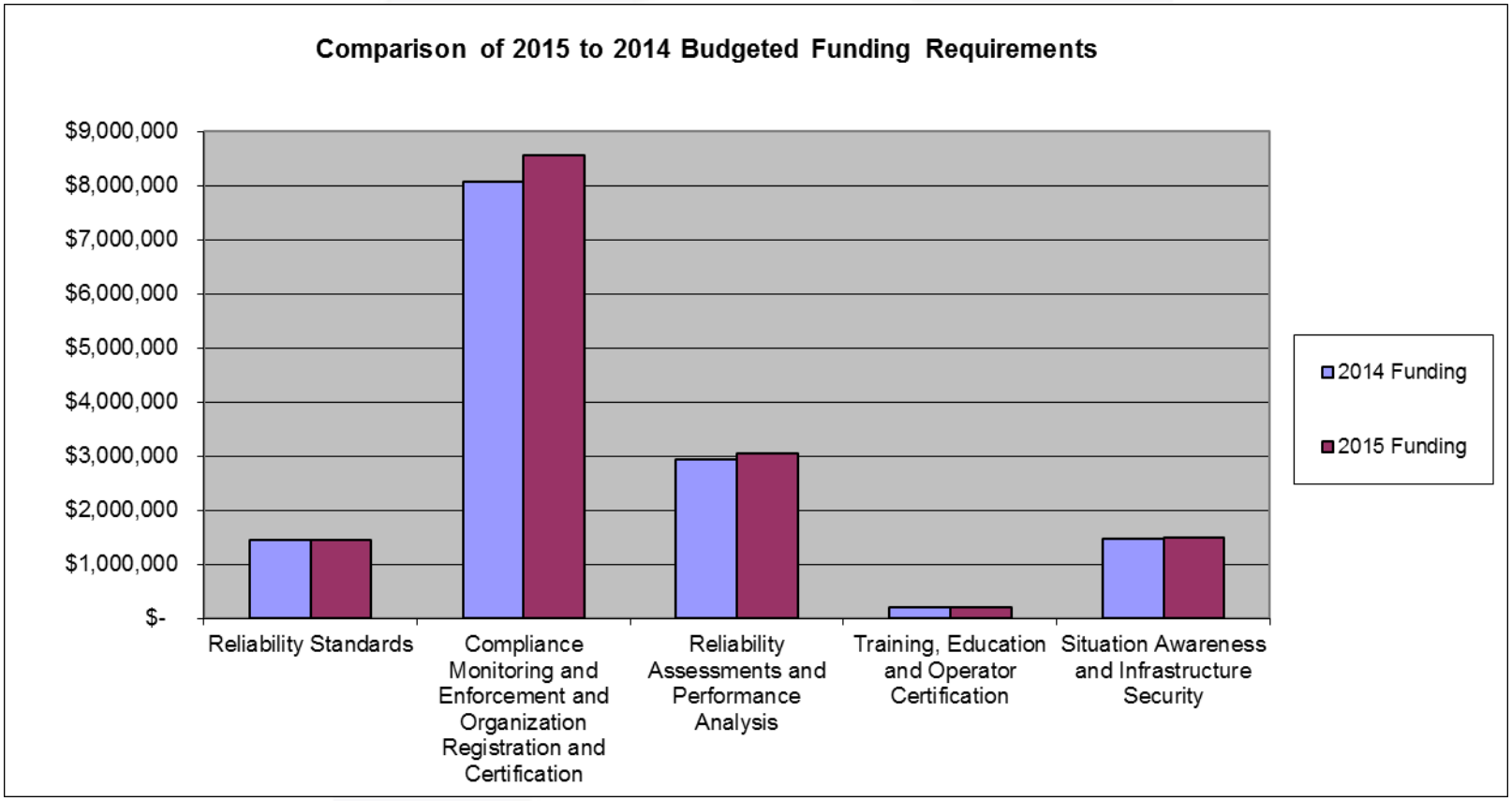
- Staffing Flat
  - 39 FTEs (Regional Entity Division 36.86, Criteria Services Division 2.14)
  - Currently one open position in Standards program area
- Salaries
  - Average wage package increase of 3%
  - Vacancy rate of 2% based on recent trends (currently one open position after 6 months fully staffed)
- Change in Operating Reserves requirement from fixed 8.33% (30 days) to a range between 8.33% and 25.00% (90 days) to provide more stability in annual funding assessments

2015 Total Resources by Program Area Regional Entity (RE) Division



Summary Comparison by Program

Regional Entity (RE) Division



2014-2015 RE Budget Comparison

	2015	2014	Variance	% Variance	Explanation
Funding					
Assessments	14,078,378	13,611,880	466,498	3.43%	
Penalties	281,000	153,000	128,000	83.66%	
Other Income	64,000	64,000	-	0.00%	
Total Funding	14,423,378	13,828,880	594,498		
Expenses					
Personnel Expenses	8,929,241	8,850,160	79,081	0.89%	3% average wage package increase; 2% vacancy rate
Meetings	365,000	365,000	-	0.00%	
Travel	890,000	890,000	-	0.00%	
Conference Calls	45,000	77,000	(32,000)	-41.56%	Lower negotiated rate with a new vendor
Consultants and Contracts	2,342,000	1,924,433	417,567	21.70%	Increase in compliance and RAPA
Rent & Improvements	751,500	737,272	14,228	1.93%	
Office Costs	578,700	536,500	42,200	7.87%	Increase in computer/network maintenance costs
Professional Services	1,025,000	966,500	58,500	6.05%	
Miscellaneous	40,000	80,000	(40,000)	-50.00%	Continuing efforts to control costs
Depreciation	202,019	250,000	(47,981)	-19.19%	Assets becoming fully depreciated in 2014
Indirect Expenses	(409,902)	(405,859)	(4,043)	1.00%	
Other Non-Operating Expenses	-	-	-		
Total Expenses	14,758,558	14,271,006	487,552	3.42%	
Increase(Decrease) in Fixed Assets	19,981	(142,000)	161,981		
Total Budget	14,778,539	14,129,006	649,533	4.60%	
Change in Working Capital	(355,161)	(300,126)	(55,035)		

NPCC, Inc.

FTE Comparison

Total FTE's by Program Area	Budget 2014	Projection 2014	Direct FTEs 2015 Budget	Shared FTEs[1] 2015 Budget	Total FTEs 2015 Budget	Change from 2014 Budget
REGIONAL ENTITY DIVISION						
Operational Programs						
Reliability Standards	2.93	2.93	2.00	0.93	2.93	0.00
Compliance Monitoring and Enforcement and Organization Registration and Certification	16.00	16.00	16.00	0.00	16.00	0.00
Training, Education, and Operator Certification	0.10	0.10	0.10	0.00	0.10	0.00
Reliability Assessment and Performance Analysis	5.83	5.83	4.90	0.93	5.83	0.00
Situation Awareness and Infrastructure Security	3.00	3.00	3.00	0.00	3.00	0.00
Total FTEs Operational Programs	**27.86**	**27.86**	**26.00**	**1.86**	**27.86**	**0.00**
Administrative Programs						
Technical Committees and Member Forums	0.50	0.50	0.50	0.00	0.50	0.00
General and Administrative	2.50	2.50	2.50	0.00	2.50	0.00
Information Technology	3.00	3.00	3.00	0.00	3.00	0.00
Legal and Regulatory	1.00	1.00	1.00	0.00	1.00	0.00
Human Resources	1.00	1.00	1.00	0.00	1.00	0.00
Accounting and Finance	1.00	1.00	1.00	0.00	1.00	0.00
Total FTEs Administrative Programs	**9.00**	**9.00**	**9.00**	**0.00**	**9.00**	**0.00**
Total FTEs	**36.86**	**36.86**	**35.00**	**1.86**	**36.86**	**0.00**

[1]A shared FTE is defined as an employee who performs both Regional Entity and Criteria Services division functions.

Resource Adequacy

- Resource assessment and reprioritization from the 2014 Business Plan and Budget has been conducted and will continue through 2015.

- Full impact of Reliability Assurance Initiative (RAI), Risk Assessment, Internal Control Evaluation, and CIP V5 implementation is currently unknown
  - Compliance staffing, in combination with increase in contractors, is expected to be adequate
- Full impact of revised BES definition implementation is currently unknown
  - RAPA staffing, in combination with increase in contractors, is expected to be adequate to address BES identification/exception requests

Process Improvements

- Implementation of CEAP in NERC Standards Development Process
- Utilization of consistent audit checklist and handbook with audits informed by evaluation of entity risk profile
- Enhanced FFT and introduction of compliance exception principles
- Expedited processing of self-reports
- Increased scheduling rigor in settlement processing
- Implementation of efficient BES Notification and Exception Processing
- Improved integration of Events Analysis processing across ERO

Alignment of RE and ERO

- Fully aligned with ERO Enterprise Strategic Plan and Performance Metrics
- Functional initiatives/activities within program areas references applicable ERO goals within the business plan using footnotes
- CS Division continues to support international, interconnected BPS reliability through compliance monitoring with more-stringent, regionally-specific reliability criteria

Efficiency and Controlling Costs

- Ongoing efforts to hold more meetings on site and via conference call or webinar.
- Limiting number of staff attending offsite meetings.
- Continued expansion of pre-audit processing to contain the time required of an audit team to be on-site in order to complete an audit and, therefore, to complete audits more cost-efficiently.

Working Capital and Operating Reserves

- Change in Operating Reserves requirement from fixed 8.33% (30 days) to a range between 8.33% and 25.00% (90 days) to provide more stability in annual funding assessments.

- Working Capital requirement remains unchanged with a targeted level of 8.33% (30 days) of the annual budget.

- No utilization of reserves is contemplated; Board authorization would be required

Questions?

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Processes Manual

VERSION 3

Effective: June 26, 2013

to ensure the reliability of the bulk power system

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Section 1.0: Introduction

1.1: Authority
This manual is published by the authority of the NERC Board of Trustees. The Board of Trustees, as necessary to maintain NERC's certification as the Electric Reliability Organization ("ERO"), may file the manual with Applicable Governmental Authorities for approval as an ERO document. When approved, the manual is appended to and provides implementation detail in support of the ERO Rules of Procedure Section 300 — Reliability Standards Development.

Capitalized terms not otherwise defined herein, shall have the meaning set forth in the Definitions Used in the Rules of Procedure, Appendix 2 to the Rules of Procedure.

1.2: Scope
The policies and procedures in this manual shall govern the activities of the North American Electric Reliability Corporation ("NERC") related to the development, approval, revision, reaffirmation, and withdrawal of Reliability Standards, Interpretations, Violation Risk Factors ("VRFs"), Violation Severity Levels ("VSLs"), definitions, Variances, and reference documents developed to support standards for the Reliable Operation and planning of the North American Bulk Power Systems.

This manual also addresses the role of the Standards Committee, drafting team and ballot body in the development and approval of Compliance Elements in conjunction with standard development.

1.3: Background
NERC is a nonprofit corporation formed for the purpose of becoming the North American ERO. NERC works with all stakeholder segments of the electric industry, including electricity users, to develop Reliability Standards for the reliability planning and Reliable Operation of the North American Bulk Power Systems. In the United States, the Energy Policy Act of 2005 added Section 215 to the Federal Power Act for the purpose of establishing a framework to make Reliability Standards mandatory for all Bulk Power System owners, operators, and users. Similar authorities are provided by Applicable Governmental Authorities in Canada. NERC was certified as the ERO effective July 2006. *North American Electric Reliability Corp*., 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030 (2007).

1.4: Essential Attributes of NERC's Reliability Standards Processes
NERC's Reliability Standards development processes provide reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing a proposed Reliability Standard consistent with the attributes necessary for American National Standards Institute ("ANSI") accreditation. The same attributes, as well as transparency, consensus-building, and timeliness, are also required under the ERO Rules of Procedure Section 304.

- ***Open Participation***
  Participation in NERC's Reliability Standards development balloting and approval processes shall be open to all entities materially affected by NERC's Reliability Standards. There shall be no financial barriers to participation in NERC's Reliability Standards balloting and approval processes. Membership in the Registered Ballot Body shall not be conditional upon membership in any organization, nor unreasonably restricted on the basis of technical qualifications or other such requirements.

- ***Balance***
  NERC's Reliability Standards development processes shall not be dominated by any two interest categories, individuals, or organizations and no single interest category, individual, or organization is able to defeat a matter.

  NERC shall use a voting formula that allocates each industry Segment an equal weight in determining the final outcome of any Reliability Standard action. The Reliability Standards development processes shall have a balance of interests. Participants from diverse interest categories shall be encouraged to join the Registered Ballot Body and participate in the balloting process, with a goal of achieving balance between the interest categories. The Registered Ballot Body serves as the consensus body voting to approve each new or proposed Reliability Standard, definition, Variance, and Interpretation.

- ***Coordination and harmonization with other American National Standards activities***
  NERC is committed to resolving any potential conflicts between its Reliability Standards development efforts and existing American National Standards and candidate American National Standards.

- ***Notification of standards development***
  NERC shall publicly distribute a notice to each member of the Registered Ballot Body, and to each stakeholder who indicates a desire to receive such notices, for each action to create, revise, reaffirm, or withdraw a Reliability Standard, definition, or Variance; and for each proposed Interpretation. Notices shall be distributed electronically, with links to the relevant information, and notices shall be posted on NERC's Reliability Standards web page. All notices shall identify a readily available source for further information.

- ***Transparency***
  The process shall be transparent to the public.

- ***Consideration of views and objections***
  Drafting teams shall give prompt consideration to the written views and objections of all participants as set forth herein. Drafting teams shall make an effort to resolve each objection that is related to the topic under review.

- ***Consensus Building***
  The process shall build and document consensus for each Reliability Standard, both with regard to the need and justification for the Reliability Standard and the content of the Reliability Standard.

- ***Consensus vote***
  NERC shall use its voting process to determine if there is sufficient consensus to approve a proposed Reliability Standard, definition, Variance, or Interpretation. NERC shall form a ballot pool for each Reliability Standard action from interested members of its Registered Ballot Body. Approval of any Reliability Standard action requires:

  - A quorum, which is established by at least 75% of the members of the ballot pool submitting a response excluding unreturned ballots; and
  - A two-thirds majority of the weighted Segment votes cast shall be affirmative. The number of votes cast during all stages of balloting except the final ballot is the sum of affirmative and negative votes with comments, excluding abstentions, non-responses, and

negative votes without comments. During the final ballot, the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and non-responses.

- ***Timeliness***
  Development of Reliability Standards shall be timely and responsive to new and changing priorities for reliability of the Bulk Power System.

- ***Metric Policy***
  The International System of units is the preferred units of measurement in NERC Reliability Standard. However, because NERC's Reliability Standards apply in Canada, the United States and portions of Mexico, where applicable, measures are provided in both the metric and English units.

1.5: Ethical Participation

All participants in the NERC Standard development process, including drafting teams, quality reviewers, Standards Committee members and members of the Registered Ballot Body, are obligated to act in an ethical manner in the exercise of all activities conducted pursuant to the terms and conditions of the Standard Processes Manual and the standard development process.

Section 2.0: Elements of a Reliability Standard

2.1: Definition of a Reliability Standard

A Reliability Standard includes a set of Requirements that define specific obligations of owners, operators, and users of the North American Bulk Power Systems. The Requirements shall be material to reliability and measurable. A Reliability Standard is defined as follows:

> "Reliability Standard" means a requirement to provide for Reliable Operation of the Bulk Power System, including without limiting the foregoing, requirements for the operation of existing Bulk Power System Facilities, including cyber security protection, and including the design of planned additions or modifications to such Facilities to the extent necessary for Reliable Operation of the Bulk Power System, but the term does not include any requirement to enlarge Bulk Power System Facilities or to construct new transmission capacity or generation capacity. A Reliability Standard shall not be effective in the United States until approved by the Federal Energy Regulatory Commission and shall not be effective in other jurisdictions until made or allowed to become effective by the Applicable Governmental Authority. *See* Appendix 2 to the NERC Rules of Procedure, Definitions Used in the Rules of Procedure.

2.2: Reliability Principles

NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American Bulk Power Systems.[1] Each Reliability Standard shall enable or support one or more of the reliability principles, thereby ensuring that each Reliability Standard serves a purpose in support of reliability of the North American Bulk Power Systems. Each Reliability Standard shall also be consistent with all of the reliability principles, thereby ensuring that no Reliability Standard undermines reliability through an unintended consequence.

2.3: Market Principles

Recognizing that Bulk Power System reliability and electricity markets are inseparable and mutually interdependent, all Reliability Standards shall be consistent with the market interface principles.[2] Consideration of the market interface principles is intended to ensure that Reliability Standards are written such that they achieve their reliability objective without causing undue restrictions or adverse impacts on competitive electricity markets.

2.4: Types of Reliability Requirements

Generally, each Requirement of a Reliability Standard shall identify what Functional Entities shall do, and under what conditions, to achieve a specific reliability objective. Although Reliability Standards all follow this format, several types of Requirements may exist, each with a different approach to measurement.

- **Performance-based Requirements** define a specific reliability objective or outcome achieved by one or more entities that has a direct, observable effect on the reliability of the Bulk Power System, *i.e.* an effect that can be measured using power system data or trends. In its simplest form, a performance-based requirement has four components: *who,*

[1] The intent of the set of NERC Reliability Standards is to deliver an adequate level of reliability. The latest set of reliability principles and the latest set of characteristics associated with an adequate level of reliability are posted on the Reliability Standards Resources web page.

[2] The latest set of market interface principles is posted on the Reliability Standards Resources web page.

under what conditions (if any), shall perform what action, to achieve what particular result or outcome.

- **Risk-based Requirements** define actions by one or more entities that reduce a stated risk to the reliability of the Bulk Power System and can be measured by evaluating a particular product or outcome resulting from the required actions. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the Bulk Power System.*

- **Capability-based Requirements** define capabilities needed by one or more entities to perform reliability functions and can be measured by demonstrating that the capability exists as required. A capability-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the Bulk Power System.*

The body of reliability Requirements collectively provides a defense-in-depth strategy supporting reliability of the Bulk Power System.

2.5: Elements of a Reliability Standard

A Reliability Standard includes several components designed to work collectively to identify what entities must do to meet their reliability-related obligations as an owner, operator or user of the Bulk Power System.

The components of a Reliability Standard may include the following:

Title: A brief, descriptive phrase identifying the topic of the Reliability Standard.

Number: A unique identification number assigned in accordance with a published classification system to facilitate tracking and reference to the Reliability Standards.[3]

Purpose: The reliability outcome achieved through compliance with the Requirements of the Reliability Standard.

Applicability: Identifies which entities are assigned reliability requirements. The specific Functional Entities and Facilities to which the Reliability Standard applies.

Effective Dates: Identification of the date or pre-conditions determining when each Requirement becomes effective in each jurisdiction.

Requirement: An explicit statement that identifies the Functional Entity responsible, the action or outcome that must be achieved, any conditions achieving the action or outcome, and the reliability-related benefit of the action or outcome. Each Requirement shall be a statement for which compliance is mandatory.

Compliance Elements: Elements to aid in the administration of ERO compliance monitoring and enforcement responsibilities.[4]

[3] Reliability Standards shall be numbered in accordance with the NERC Standards Numbering Convention as provide on the Reliability Standards Resources web page.

- ***Measure:*** Provides identification of the evidence or types of evidence that may demonstrate compliance with the associated requirement.

- ***Violation Risk Factors and Violation Severity Levels:*** Violation risk factors (VRFs) and violation severity levels (VSLs) are used as factors when determining the size of a penalty or sanction associated with the violation of a requirement in an approved reliability standard.[5] Each requirement in each reliability standard has an associated VRF and a set of VSLs. VRFs and VSLs are developed by the drafting team, working with NERC Staff, at the same time as the associated reliability standard, but are not part of the reliability standard. The Board of Trustees is responsible for approving VRFs and VSLs.

  - ***Violation Risk Factors***
    VRFs identify the potential reliability significance of noncompliance with each requirement. Each requirement is assigned a VRF in accordance with the latest approved set of VRF criteria.[6]

  - ***Violation Severity Levels***
    VSLs define the degree to which compliance with a requirement was not achieved. Each requirement shall have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs. Each requirement is assigned one or more VSLs in accordance with the latest approved set of VSL criteria.7

Version History: The version history is provided for informational purposes and lists information regarding prior versions of Reliability Standards.

Variance: A Requirement (to be applied in the place of the continent-wide Requirement) that is applicable to a specific geographic area or to a specific set of Registered Entities.

Compliance Enforcement Authority: The entity that is responsible for assessing performance or outcomes to determine if an entity is compliant with the associated Reliability Standard. The Compliance Enforcement Authority will be NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

***Application guidelines*:** Guidelines to support the implementation of the associated Reliability Standard.

***Procedures*:** Procedures to support implementation of the associated Reliability Standard.

The only mandatory and enforceable components of a Reliability Standard are the: (1) applicability, (2) Requirements, and the (3) effective dates. The additional components are included in the Reliability Standard for informational purposes, to establish the relevant scope and technical paradigm, and to

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[4] It is the responsibility of the ERO staff to develop compliance tools for each standard; these tools are not part of the standard but are referenced in this manual because the preferred approach to developing these tools is to use a transparent process that leverages the technical and practical expertise of the drafting team and ballot pool..
[5] The *Sanction Guidelines of the North American Electric Reliability Corporation* identifies the factors used to determine a penalty or sanction for violation of reliability standard and is posted on the NERC Web Site.
[6] The latest set of approved VRF Criteria is posted on the Reliability Standards Resources Web Page.
[7] The latest set of approved VSL Criteria is posted on the Reliability Standards Resources Web Page.

provide guidance to Functional Entities concerning how compliance will be assessed by the Compliance Enforcement Authority.

Section 3.0: Reliability Standards Program Organization

3.1: Board of Trustees

The NERC Board of Trustees shall consider for adoption Reliability Standards, definitions, Variances and Interpretations and associated implementation plans that have been processed according to the processes identified in this manual. Once the Board adopts a Reliability Standard, definition, Variance or Interpretation, the Board shall direct NERC Staff to file the document(s) for approval with Applicable Governmental Authorities.

3.2: Registered Ballot Body

The Registered Ballot Body comprises all entities or individuals that qualify for one of the Segments approved by the Board of Trustees[8], and are registered with NERC as potential ballot participants in the voting on Reliability Standards. Each member of the Registered Ballot Body is eligible to join the ballot pool for each Reliability Standard action.

3.3: Ballot Pool

Each Reliability Standard action has its own ballot pool formed of interested members of the Registered Ballot Body. The ballot pool comprises those members of the Registered Ballot Body that respond to a pre-ballot request to participate in that particular Reliability Standard action. The ballot pool votes on each Reliability Standards action. The ballot pool remains in place until all balloting related to that Reliability Standard action has been completed.

3.4: Standards Committee

The Standards Committee serves at the pleasure and direction of the NERC Board of Trustees, and the Board approves the Standards Committee's Charter.[9] Standards Committee members are elected by their respective Segment's stakeholders. The Standards Committee consists of two members of each of the Segments in the Registered Ballot Body.[10] A member of the NERC Reliability Standards Staff shall serve as the non-voting secretary to the Standards Committee.

The Standards Committee is responsible for managing the Reliability Standards processes for development of Reliability Standards, definitions, Variances and Interpretations in accordance with this manual. The responsibilities of the Standards Committee are defined in detail in the Standards Committee's Charter. The Standards Committee is responsible for ensuring that the Reliability Standards, definitions, Variances and Interpretations developed by drafting teams are developed in accordance with the processes in this manual and meet NERC's benchmarks for Reliability Standards as well as criteria for governmental approval.[11]

The Standards Committee has the right to remand work to a drafting team, to reject the work of a drafting team, or to accept the work of a drafting team. The Standards Committee may disband a drafting team if it determines (a) that the drafting team is not producing a standard in a timely manner; (b) the drafting

[8] The industry Segment qualifications are described in the Development of the Registered Ballot Body and Segment Qualification Guidelines document posted on the Reliability Standards Resources web page and are included in Appendix 3D of the NERC Rules of Procedure.

[9] The Standards Committee Charter is posted on the Reliability Standards Resources web page.

[10] In addition to balanced Segment representation, the Standards Committee shall also have representation that is balanced among countries based on Net Energy for Load ("NEL"). As needed, the Board of Trustees may approve special procedures for the balancing of representation among countries represented within NERC.

[11] The Ten Benchmarks of an Excellent Reliability Standard and FERC's Criteria for Approving Reliability Standards are posted on the Reliability Standards Resources web page.

team is not able to produce a standard that will achieve industry consensus; (c) the drafting team has not addressed the scope of the SAR; or (d) the drafting team has failed to fully address a regulatory directive or otherwise provided a responsive or equally efficient and effective alternative. The Standards Committee may direct a drafting team to revise its work to follow the processes in this manual or to meet the criteria for NERC's benchmarks for Reliability Standards, or to meet the criteria for governmental approval; however, the Standards Committee shall not direct a drafting team to change the technical content of a draft Reliability Standard.

The Standards Committee shall meet at regularly scheduled intervals (either in person, or by other means). All Standards Committee meetings are open to all interested parties.

3.5: NERC Reliability Standards Staff

The NERC Reliability Standards Staff, led by the Director of Standards, is responsible for administering NERC's Reliability Standards processes in accordance with this manual. The NERC Reliability Standards Staff provides support to the Standards Committee in managing the Reliability Standards processes and in supporting the work of all drafting teams. The NERC Reliability Standards Staff works to ensure the integrity of the Reliability Standards processes and consistency of quality and completeness of the Reliability Standards. The NERC Reliability Standards Staff facilitates all steps in the development of Reliability Standards, definitions, Variances, Interpretations and associated implementation plans.

The NERC Reliability Standards Staff is responsible for presenting Reliability Standards, definitions, Variances, and Interpretations to the NERC Board of Trustees for adoption. When presenting Reliability Standards-related documents to the NERC Board of Trustees for adoption or approval, the NERC Reliability Standards Staff shall report the results of the associated stakeholder ballot, including identification of unresolved stakeholder objections and an assessment of the document's practicality and enforceability.

3.6: Drafting Teams

The Standards Committee shall appoint industry experts to drafting teams to work with stakeholders in developing and refining Standard Authorization Requests ("SARs"), Reliability Standards, definitions, and Variances. The NERC Reliability Standards Staff shall appoint drafting teams that develop Interpretations. The NERC Reliability Standards Staff shall provide, or solicit from the industry, essential support for each of the drafting teams in the form of technical writers, legal, compliance, and rigorous and highly trained project management and facilitation support personnel.

Each drafting team may consist of a group of technical, legal, and compliance experts that work cooperatively with the support of the NERC Reliability Standards Staff.[12] The technical experts provide the subject matter expertise and guide the development of the technical aspects of the Reliability Standard, assisted by technical writers, legal and compliance experts. The technical experts maintain authority over the technical details of the Reliability Standard. Each drafting team appointed to develop a Reliability Standard is responsible for following the processes identified in this manual as well as procedures developed by the Standards Committee from the inception of the assigned project through the final acceptance of that project by Applicable Governmental Authorities.

Collectively, each drafting team:

- Drafts proposed language for the Reliability Standards, definitions, Variances, and/or Interpretations and associated implementation plans.

[12] The detailed responsibilities of drafting teams are outlined in the Drafting Team Guidelines, which is posted on the Reliability Standards Resources web page.

- Develops and refines technical documents that aid in the understanding of Reliability Standards.
- Works collaboratively with NERC Compliance Monitoring and Enforcement Staff to develop Reliability Standard Audit Worksheets ("RSAWs") at the same time Reliability Standards are developed.
- Provides assistance to NERC Staff in the development of Compliance Elements of proposed Reliability Standards.
- Solicits, considers, and responds to comments related to the specific Reliability Standards development project.
- Participates in industry forums to help build consensus on the draft Reliability Standards, definitions, Variances, and/or Interpretations and associated implementation plans.
- Assists in developing the documentation used to obtain governmental approval of the Reliability Standards, definitions, Variances, and/or Interpretations and associated implementation plans.

All drafting teams report to the Standards Committee.

3.7: Governmental Authorities

The Federal Energy Regulatory Commission ("FERC") in the United States of America, and where permissible by statute or regulation, the provincial government of each of the eight Canadian Provinces (Manitoba, Nova Scotia, Saskatchewan, Alberta, Ontario, British Columbia, New Brunswick and Quebec) and the National Energy Board of Canada have the authority to approve each new, revised or withdrawn Reliability Standard, definition, Variance, VRF, VSL and Interpretation following adoption or approval by the NERC Board of Trustees.

3.8: Committees, Subcommittees, Working Groups, and Task Forces

NERC's technical committees, subcommittees, working groups, and task forces provide technical research and analysis used to justify the development of new Reliability Standards and provide guidance, when requested by the Standards Committee, in overseeing field tests or collection and analysis of data. The technical committees, subcommittees, working groups, and task forces provide feedback to drafting teams during both informal and formal comment periods.

The Standards Committee may request that a NERC technical committee or other group prepare a Technical document to support development of a proposed Reliability Standard.

The technical committees, subcommittees, working groups, and task forces share their observations regarding the need for new or modified Reliability Standards or Requirements with the NERC Reliability Standards Staff for use in identifying the need for new Reliability Standards projects for the three-year *Reliability Standards Development Plan*.

3.9: Compliance and Certification Committee

The Compliance and Certification Committee is responsible for monitoring NERC's compliance with its Reliability Standards processes and procedures and for monitoring NERC's compliance with the Rules of Procedure regarding the development of new or revised Reliability Standards, definitions, Variances, and Interpretations. The Compliance and Certification Committee may assist in verifying that each proposed Reliability Standard is enforceable as written before the Reliability Standard is posted for formal stakeholder comment and balloting.

3.10: Compliance Monitoring and Enforcement Program

As applicable, the NERC Compliance Monitoring and Enforcement Program Staff manages and enforces compliance with approved Reliability Standards. Compliance Monitoring and Enforcement Staff are responsible for the development of select compliance tools. The drafting team and the Compliance Monitoring and Enforcement Program Staff shall work together during the Reliability Standard development process to ensure an accurate and consistent understanding of the Requirements and their intent, and to ensure that applicable compliance tools accurately reflect that intent. The goal of this collaboration is to ensure that application of the Reliability Standards in the Compliance Monitoring and Enforcement Program by NERC and the Regional Entities is consistent.

The Compliance Monitoring and Enforcement Program is encouraged to share its observations regarding the need for new or modified Requirements with the NERC Reliability Standards Staff for use in identifying the need for new Reliability Standards projects.

3.11: North American Energy Standards Board ("NAESB")

While NERC has responsibility for developing Reliability Standards to support reliability, NAESB has responsibility for developing business practices and coordination between reliability and business practices as needed. NERC and NAESB developed and approved a procedure[13] to guide the development of Reliability Standards and business practices where the reliability and business practice components are intricately entwined within a proposed Reliability Standard.

[13] The NERC NAESB Template Procedure for Joint Standards Development and Coordination is posted on the Reliability Standards Resources web page.

Section 4.0: Process for Developing, Modifying, Withdrawing or Retiring a Reliability Standard

There are several steps to the development, modification, withdrawal or retirement of a Reliability Standard.[14]

The development of the *Reliability Standards Development Plan* is the appropriate forum for reaching agreement on whether there is a need for a Reliability Standard and the scope of a proposed Reliability Standard. A typical process for a project identified in the *Reliability Standards Development Plan* that involves a revision to an existing Reliability Standard is shown below. Note that most projects do not include a field test.

[14] The process described is also applicable to projects used to propose a new or modified definition or Variance or to propose retirement of a definition or Variance.

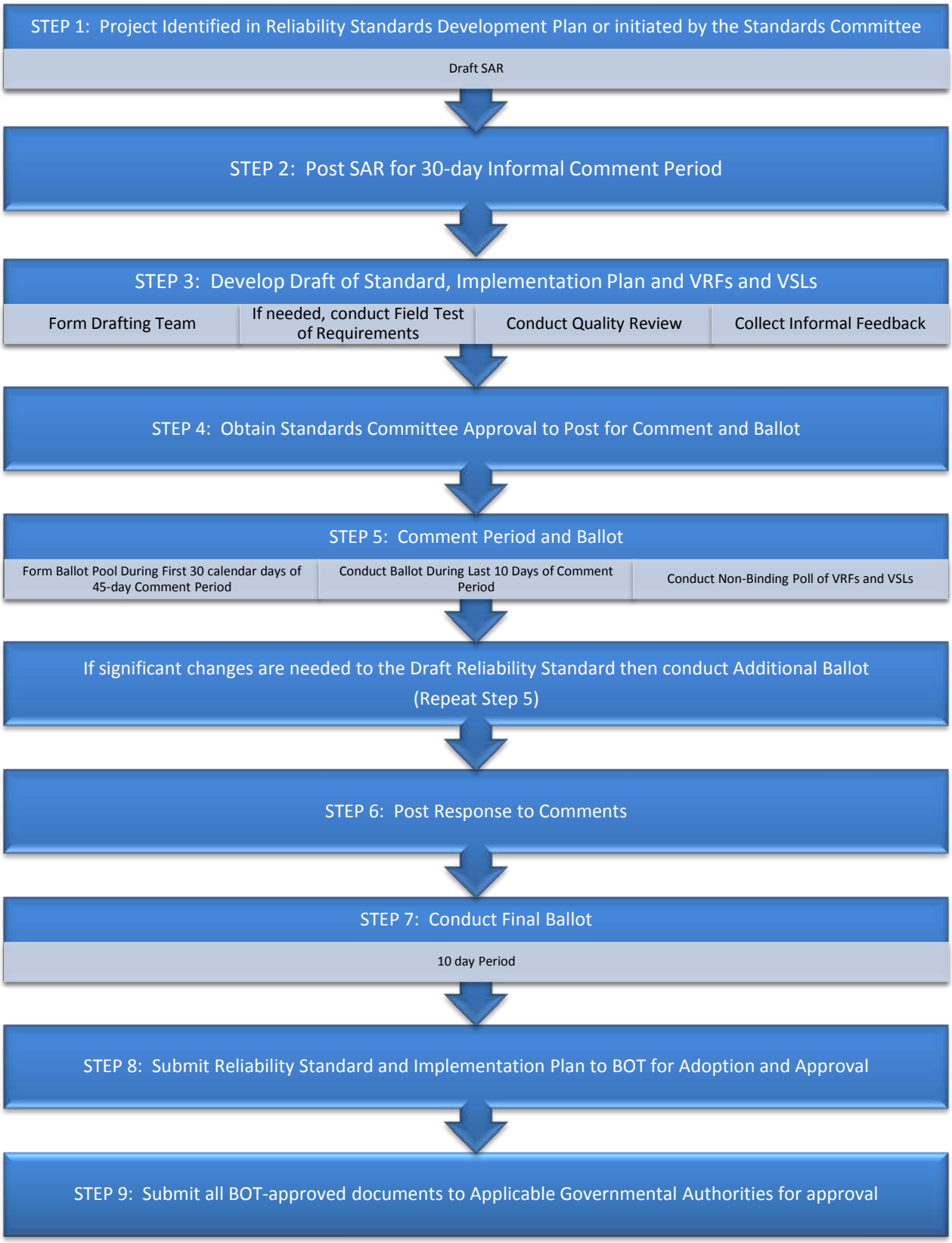


FIGURE 1: Process for Developing or Modifying a Reliability Standard

4.1: Posting and Collecting Information on SARs

Standard Authorization Request

A Standard Authorization Request ("SAR") is the form used to document the scope and reliability benefit of a proposed project for one or more new or modified Reliability Standards or definitions or the benefit of retiring one or more approved Reliability Standards. Any entity or individual, including NERC committees or subgroups and NERC Staff, may propose the development of a new or modified Reliability Standard, or may propose the retirement of a Reliability Standard (in whole or in part), by submitting a completed SAR[15] to the NERC Reliability Standards Staff. The Standards Committee has the authority to approve the posting of all SARs for projects that propose (i) developing a new or modified Reliability Standard or definition or (ii) propose retirement of an existing Reliability Standard (or elements thereof).

The NERC Reliability Standards Staff sponsors an open solicitation period each year seeking ideas for new Reliability Standards projects (using *Reliability Standards Suggestions and Comments forms*). The open solicitation period is held in conjunction with the annual revision to the *Reliability Standards Development Plan*. While the Standards Committee prefers that ideas for new projects be submitted during this annual solicitation period through submittal of a *Reliability Standards Suggestions and Comments Form*,[16] a SAR proposing a specific project may be submitted to the NERC Reliability Standards Staff at any time.

Each SAR that proposes a "new" or substantially revised Reliability Standard or definition should be accompanied by a technical justification that includes, as a minimum, a discussion of the reliability-related benefits and costs of developing the new Reliability Standard or definition, and a technical foundation document (*e.g.*, research paper) to guide the development of the Reliability Standard or definition. The technical document should address the engineering, planning and operational basis for the proposed Reliability Standard or definition, as well as any alternative approaches considered during SAR development.

The NERC Reliability Standards Staff shall review each SAR and work with the submitter to verify that all required information has been provided. All properly completed SARs shall be submitted to the Standards Committee for action at the next regularly scheduled Standards Committee meeting.

When presented with a SAR, the Standards Committee shall determine if the SAR is sufficiently complete to guide Reliability Standard development and whether the SAR is consistent with this manual. The Standards Committee shall take one of the following actions:

- Accept the SAR.
- Remand the SAR back to the requestor or to NERC Reliability Standards Staff for additional work.
- Reject the SAR. The Standards Committee may reject a SAR for good cause. If the Standards Committee rejects a SAR, it shall provide a written explanation for rejection to the sponsor within ten days of the rejection decision.
- Delay action on the SAR pending one of the following: (i) development of a technical justification for the proposed project; or (ii) consultation with another NERC Committee to determine if there is another approach to addressing the issue raised in the SAR.

If the Standards Committee is presented with a SAR that proposes developing a new Reliability Standard or definition but does not have a technical justification upon which the Reliability Standard or definition

[15] The SAR form can be downloaded from the Reliability Standards Resources web page.
[16] The *Reliability Standards Suggestions and Comments Form* can be downloaded from the Reliability Standards Resources web page.

can be developed, the Standards Committee shall direct the NERC Reliability Standards Staff to post the SAR for a 30-day comment period solely to collect stakeholder feedback on the scope of technical foundation, if any, needed to support the proposed project. If a technical foundation is determined to be necessary, the Standards Committee shall solicit assistance from NERC's technical committees or other industry experts to provide that foundation before authorizing development of the associated Reliability Standard or definition.

During the SAR comment process, the drafting team may become aware of potential regional Variances related to the proposed Reliability Standard. To the extent possible, any regional Variances or exceptions should be made a part of the SAR so that if the SAR is authorized, such variations shall be made a part of the draft new or revised Reliability Standard.

If the Standards Committee accepts a SAR, the project shall be added to the list of approved projects. The Standards Committee shall assign a priority to the project, relative to all other projects under development, and those projects already identified in the *Reliability Standards Development Plan* that are already approved for development.

The Standards Committee shall work with the NERC Reliability Standards Staff to coordinate the posting of SARs for new projects, giving consideration to each project's priority.

4.2: SAR Posting

When the Standards Committee determines it is ready to initiate a new project, the Standards Committee shall direct NERC Staff to post the project's SAR in accordance with the following:

- For SARs that are limited to addressing regulatory directives, or revisions to Reliability Standards that have had some vetting in the industry, authorize posting the SAR for a 30-day informal comment period with no requirement to provide a formal response to the comments received.
- For SARs that address the development of new projects or Reliability Standards, authorize posting the SAR for a 30-day formal comment period.

If a SAR for a new Reliability Standard is posted for a formal comment period, the Standards Committee shall appoint a drafting team to work with the NERC Staff coordinator to give prompt consideration of the written views and objections of all participants. The Standards Committee may use a public nomination process to populate the Reliability Standard drafting team, or may use another method that results in a team that collectively has the necessary technical expertise and work process skills to meet the objectives of the project. In some situations, an *ad hoc* team may already be in place with the requisite expertise, competencies, and diversity of views that are necessary to refine the SAR and develop the Reliability Standard, and additional members may not be needed. The drafting team shall address all comments submitted, which may be in the form of a summary response addressing each of the issues raised in comments received, during the public posting period. An effort to resolve all expressed objections shall be made, and each objector shall be advised of the disposition of the objection and the reasons therefore. If the drafting team concludes that there is not sufficient stakeholder support to continue to refine the SAR, the team may recommend that the Standards Committee direct curtailment of work on the SAR.

While there is no established limit on the number of times a SAR may be posted for comment, the Standards Committee retains the right to reverse its prior decision and reject a SAR if it believes continued revisions are not productive. The Standards Committee shall notify the sponsor in writing of the rejection within 10 calendar days.

If stakeholders indicate support for the project proposed with the SAR, the drafting team shall present its work to the Standards Committee with a request that the Standards Committee authorize development of the associated Reliability Standard.

The Standards Committee, once again considering the public comments received and their resolution, may then take one of the following actions:

- Authorize drafting the proposed Reliability Standard or revisions to a Reliability Standard.
- Reject the SAR with a written explanation to the sponsor and post that explanation.

4.3: Form Drafting Team

When the Standards Committee is ready to have a drafting team begin work on developing a new or revised Reliability Standard, the Standards Committee shall appoint a drafting team, if one was not already appointed to develop the SAR. If the Standards Committee appointed a drafting team to refine the SAR, the same drafting team shall work to develop the associated Reliability Standard.

If no drafting team is in place, then the Standards Committee may use a public nomination process to populate the Reliability Standard drafting team, or may use another method that results in a team that collectively has the necessary technical expertise, diversity of views and work process skills to accomplish the objectives of the project on a timely basis. In some situations, an ad hoc team may already be in place with the requisite expertise, competencies, and diversity of views that are necessary to develop the Reliability Standard, and additional members may not be needed.

The NERC Reliability Standards Staff shall provide one or more members as needed to support the team with facilitation, project management, compliance, legal, regulatory and technical writing expertise and shall provide administrative support to the team, guiding the team through the steps in completing its project. In developing the Reliability Standard, the individuals provided by the NERC Reliability Standards Staff serve as advisors to the drafting team and do not have voting rights but share accountability along with the drafting team members assigned by the Standards Committee for timely delivery of a final draft Reliability Standard that meets the quality attributes identified in NERC's Benchmarks for Excellent Standards. The drafting team members assigned by the Standards Committee shall have final authority over the technical details of the Reliability Standard, while the technical writer shall provide assistance to the drafting team in assuring that the final draft of the Reliability Standard meets the quality attributes identified in NERC's Benchmarks for Excellent Standards.

Once it is appointed by the Standards Committee, the Reliability Standard drafting team is responsible for making recommendations to the Standards Committee regarding the remaining steps in the Reliability Standards process. Consistent with the need to provide for timely standards development, the Standards Committee may decide a project is so large that it should be subdivided and either assigned to more than one drafting team or assigned to a single drafting team with clear direction on completing the project in specified phases. The normally expected timeframes for standards development within the context of this manual are applicable to individual standards and not to projects containing multiple standards. Alternatively, a single drafting team may address the entire project with a commensurate increase in the expected duration of the development work. If a SAR is subdivided and assigned to more than one drafting team, each drafting team will have a clearly defined portion of the work such that there are no overlaps and no gaps in the work to be accomplished.

The Standards Committee may supplement the membership of a Reliability Standard drafting team or provide for additional advisors, as appropriate, to ensure the necessary competencies and diversity of views are maintained throughout the Reliability Standard development effort.

4.4: Develop Preliminary Draft of Reliability Standard, Implementation Plan and VRFs and VSLs

4.4.1: Project Schedule

When a drafting team begins its work, either in refining a SAR or in developing or revising a proposed Reliability Standard, the drafting team shall develop a project schedule which shall be approved by the Standards Committee. The drafting team shall report progress to the Standards Committee, against the initial project schedule and any revised schedule as requested by the Standards Committee. Where project milestones cannot be completed on a timely basis, modifications to the project schedule must be presented to the Standards Committee for consideration along with proposed steps to minimize unplanned project delays.

4.4.2: Draft Reliability Standard

The team shall develop a Reliability Standard that is within the scope of the associated SAR that includes all required elements as described earlier in this manual with a goal of meeting the quality attributes identified in NERC's Benchmarks for Excellent Standards and criteria for governmental approval. The team shall document its justification for the Requirements in its proposed Reliability Standard by explaining how each meets these criteria. The standard drafting team shall document its justification for selecting each reference by explaining how each Requirement fits the category chosen.

4.4.3: Implementation Plan

As a drafting team drafts its proposed revisions to a Reliability Standard, that team is also required to develop an implementation plan to identify any factors for consideration when approving the proposed effective date or dates for the associated Reliability Standard or Standards. As a minimum, the implementation plan shall include the following:

- The proposed effective date (the date entities shall be compliant) for the Requirements.
- Identification of any new or modified definitions that are proposed for approval with the associated Reliability Standard.
- Whether there are any prerequisite actions that need to be accomplished before entities are held responsible for compliance with one or more of the Requirements.
- Whether approval of the proposed Reliability Standard will necessitate any conforming changes to any already approved Reliability Standards – and identification of those Reliability Standards and Requirements.
- The Functional Entities that will be required to comply with one or more Requirements in the proposed Reliability Standard.

A single implementation plan may be used for more than one Reliability Standard. The implementation plan is posted with the associated Reliability Standard or Standards during the 45 (calendar) day formal comment period and is balloted with the associated Reliability Standard.

4.4.4: Violation Risk Factors and Violation Severity Levels

The drafting team shall work with NERC Staff in developing a set of VRFs and VSLs that meet the latest criteria established by NERC and Applicable Governmental Authorities. The drafting team shall document its justification for selecting each VRF and for setting each set of proposed VSLs by explaining how its proposed VRFs and VSLs meet these criteria. NERC Staff is responsible for ensuring that the VRFs and VSLs proposed for stakeholder review meet these criteria.

Before the drafting team has finalized its Reliability Standard, implementation plan, and VRFs and VSLs, the team should seek stakeholder feedback on its preliminary draft documents.

4.5: Informal Feedback[17]

Drafting teams may use a variety of methods to collect informal stakeholder feedback on preliminary drafts of its documents, including the use of informal comment periods,[18] webinars, industry meetings, workshops, or other mechanisms. Information gathered from informal comment forms shall be publicly posted. While drafting teams are not required to provide a written response to each individual comment received, drafting teams are encouraged, where possible, to post a summary response that identifies how it used comments submitted by stakeholders. Drafting teams are encouraged, where possible, to reach out directly to individual stakeholders in order to facilitate resolution of identified stakeholder concerns. The intent is to gather stakeholder feedback on a "working document" before the document reaches the point where it is considered the "final draft."

4.6: Conduct Quality Review

The NERC Reliability Standards Staff shall coordinate a quality review of the Reliability Standard, implementation plan, and VRFs and VSLs in parallel with the development of the Reliability Standard and implementation plan, to assess whether the documents are within the scope of the associated SAR, whether the Reliability Standard is clear and enforceable as written, and whether the Reliability Standard meets the criteria specified in NERC's Benchmarks for Excellent Standards and criteria for governmental approval of Reliability Standards. The drafting team shall consider the results of the quality review, decide upon appropriate changes, and recommend to the Standards Committee whether the documents are ready for formal posting and balloting.

The Standards Committee shall authorize posting the proposed Reliability Standard, and implementation plan for a formal comment period and ballot and the VRFs and VSLs for a non-binding poll as soon as the work flow will accommodate.

If the Standards Committee finds that any of the documents do not meet the specified criteria, the Standards Committee shall remand the documents to the drafting team for additional work.

If the Reliability Standard is outside the scope of the associated SAR, the drafting team shall be directed to either revise the Reliability Standard so that it is within the approved scope, or submit a request to expand the scope of the approved SAR. If the Reliability Standard is not clear and enforceable as written, or if the Reliability Standard does not meet the specified criteria, the Reliability Standard shall be returned to the drafting team by the Standards Committee with specific identification of any Requirement that is deemed to be unclear or unenforceable as written.

4.7: Conduct Formal Comment Period and Ballot

Proposed new or modified Reliability Standards require a formal comment period where the new or modified Reliability Standard, implementation plan and associated VRFs and VSLs or the proposal to retire a Reliability Standard, implementation plan and associated VRFs and VSLs are posted.

The formal comment period shall be at least 45-days long. Formation of the ballot pool and Ballot of the Reliability Standard take place during this formal 45-day comment period. The intent of the formal

[17] While this discussion focuses on collecting stakeholder feedback on proposed Reliability Standards and implementation plans, the same process is used to collect stakeholder feedback on proposed new or modified Interpretations, definitions and Variances.

[18] The term "informal comment period" refers to a comment period conducted outside of the ballot process and where there is no requirement for a drafting team to respond in writing to submitted comments.

comment period(s) is to solicit very specific feedback on the final draft of the Reliability Standard, implementation plan and VRFs and VSLs.

Comments in written form may be submitted on a draft Reliability Standard by any interested stakeholder, including NERC Staff, FERC Staff, and other interested governmental authorities. If stakeholders disagree with some aspect of the proposed set of products, comments provided should explain the reasons for such disagreement and, where possible, suggest specific language that would make the product acceptable to the stakeholder.

4.8: Form Ballot Pool

The NERC Reliability Standards Staff shall establish a ballot pool during the first 30 calendar days of the 45-day formal comment period. The NERC Reliability Standards Staff shall post the proposed Reliability Standard, along with its implementation plan, VRFs and VSLs and shall send a notice to every entity in the Registered Ballot Body to provide notice that there is a new or revised Reliability Standard proposed for approval and to solicit participants for the associated ballot pool. All members of the Registered Ballot Body are eligible to join each ballot pool to vote on a new or revised Reliability Standard and its implementation plan and to participate in the non-binding poll of the associated VRFs and VSLs.

Any member of the Registered Ballot Body may join or withdraw from the ballot pool until the ballot window opens. No Registered Ballot Body member may join or withdraw from the ballot pool once the first ballot starts through the point in time where balloting for that Reliability Standard action has ended. The Director of Standards may authorize deviations from this rule for extraordinary circumstances such as the death, retirement, or disability of a ballot pool member that would prevent an entity that had a member in the ballot pool from eligibility to cast a vote during the ballot window. Any approved deviation shall be documented and noted to the Standards Committee.

4.9: Conduct Ballot and Non-binding Poll of VRFs and VSLs[19]

The NERC Reliability Standards Staff shall announce the opening of the Ballot window and the non-binding poll of VRFs and VSLs. The Ballot window and non-binding poll of VRFs and VSLs shall take place during the last 10 calendar days of the 45-day formal comment period and for the Final Ballot shall be no less than 10 calendar days. If the last day of the ballot window falls on a Saturday or Sunday, the period does not end until the next business day.[20]

The ballot and non-binding poll shall be conducted electronically. The voting window shall be for a period of 10 calendar days but shall be extended, if needed, until a quorum is achieved. During a ballot window, NERC shall not sponsor or facilitate public discussion of the Reliability Standard action under ballot.

There is no requirement to conduct a new non-binding poll of the revised VRFs and VSLs if no changes were made to the associated standard, however if the requirements are modified and conforming changes are made to the associated VRFs and VSLs, another non-binding poll of the revised VRFs and VSLs shall be conducted.

[19] While RSAWs are not part of the Reliability Standard, they are developed through collaboration of the SDT and NERC Compliance Staff. A non-binding poll, similar to what is done for VRFs and VSLs may be conducted for the RSAW developed through this process to gauge industry support for the companion RSAW to be provided for informational purposes to the NERC Board of Trustees.

[20] Closing dates may be extended as deemed appropriate by NERC Staff.

4.10: Criteria for Ballot Pool Approval

Ballot pool approval of a Reliability Standard requires:

A quorum, which is established by at least 75% of the members of the ballot pool submitting a response; and

A two-thirds majority of the weighted Segment votes cast shall be affirmative. The number of votes cast is the sum of affirmative votes and negative votes with comments. This calculation of votes for the purpose of determining consensus excludes (i) abstentions, (ii) non-responses, and (iii) negative votes without comments.

The following process[21] is used to determine if there are sufficient affirmative votes.

- For each Segment with ten or more voters, the following process shall be used: The number of affirmative votes cast shall be divided by the sum of affirmative and negative votes with comments cast to determine the fractional affirmative vote for that Segment. Abstentions, non-responses, and negative votes without comments shall not be counted for the purposes of determining the fractional affirmative vote for a Segment.
- For each Segment with less than ten voters, the vote weight of that Segment shall be proportionally reduced. Each voter within that Segment voting affirmative or negative with comments shall receive a weight of 10% of the Segment vote.
- The sum of the fractional affirmative votes from all Segments divided by the number of Segments voting[22] shall be used to determine if a two-thirds majority has been achieved. (A Segment shall be considered as "voting" if any member of the Segment in the ballot pool casts either an affirmative vote or a negative vote with comments.)
- A Reliability Standard shall be approved if the sum of fractional affirmative votes from all Segments divided by the number of voting Segments is at least two thirds.

4.11: Voting Positions

Each member of the ballot pool may **only** vote one of the following positions on the Ballot and Additional Ballot(s):

- Affirmative;
- Affirmative, with comment;
- Negative with comments;
- Abstain.

Given that there is no formal comment period concurrent with the Final Ballot, each member of the ballot pool may **only** vote one of the following positions on the Final Ballot:

- Affirmative;
- Negative;[23]
- Abstain.

[21] Examples of weighted segment voting calculation are posted on the Reliability Standards Resources web page.

[22] When less than ten entities vote in a Segment, the total weight for that Segment shall be determined as one tenth per entity voting, up to ten.

[23] The Final Ballot is used to confirm consensus achieved during the Formal Comment and Ballot stage. Ballot Pool members voting negative on the Final Ballot will be deemed to have expressed the reason for their negative ballot in their own comments or the comments of others during prior Formal Comment periods.

4.12: Consideration of Comments
If a stakeholder or balloter proposes a significant revision to a Reliability Standard during the formal comment period or concurrent Ballot that will improve the quality, clarity, or enforceability of that Reliability Standard, then the drafting team may choose to make such revisions and post the revised Reliability Standard for another 45 calendar day public comment period and ballot. Prior to posting the revised Reliability Standard for an additional comment period, the drafting team must communicate this decision to stakeholders. This communication is intended to inform stakeholders that the drafting team has identified that significant revisions to the Reliability Standard are necessary and should note that the drafting team is not required to respond in writing to comments from the previous ballot. The drafting team will respond to comments received in the last Additional Ballot prior to conducting a Final Ballot.

There is no formal comment period concurrent with the Final Ballot and no obligation for the drafting team to respond to any comments submitted during the Final Ballot.

4.13: Additional Ballots
A drafting team must respond in writing to every stakeholder written comment submitted in response to a ballot prior to conducting a Final Ballot. These responses may be provided in summary form, but all comments and objections must be responded to by the drafting team. All comments received and all responses shall be publicly posted.

However, a drafting team is not required to respond in writing to comments to the previous ballot when it determines that significant changes are needed and an Additional Ballot will be conducted.

4.14: **Conduct Final Ballot**
When the drafting team has reached a point where it has made a good faith effort at resolving applicable objections and is not making any substantive changes from the previous ballot, the team shall conduct a "Final Ballot." A non-substantive revision is a revision that does not change the scope, applicability, or intent of any Requirement and includes but is not limited to things such as correcting the numbering of a Requirement, correcting the spelling of a word, adding an obviously missing word, or rephrasing a Requirement for improved clarity. Where there is a question as to whether a proposed modification is "substantive," the Standards Committee shall make the final determination.

In the Final Ballot, members of the ballot pool shall again be presented the proposed Reliability Standard along with the reasons for negative votes from the previous ballot, the responses of the drafting team to those concerns, and any resolution of the differences.

All members of the ballot pool shall be permitted to reconsider and change their vote from the prior ballot. Members of the ballot pool who did not respond to the prior ballot shall be permitted to vote in the Final Ballot. In the Final Ballot, votes shall be counted by exception only — members on the Final Ballot may indicate a revision to their original vote; otherwise their vote shall remain the same as in their prior ballot.

4.15: Final Ballot Results
There are no limits to the number of public comment periods and ballots that can be conducted to result in a Reliability Standard or interpretation that is clear and enforceable, and achieves a quorum and sufficient affirmative votes for approval. The Standards Committee has the authority to conclude this process for a particular Reliability Standards action if it becomes obvious that the drafting team cannot develop a Reliability Standard that is within the scope of the associated SAR, is sufficiently clear to be enforceable, and achieves the requisite weighted Segment approval percentage.

The NERC Reliability Standards Staff shall post the final outcome of the ballot process. If the Reliability Standard is rejected, the Standards Committee may decide whether to end all further work on the

proposed standard, return the project to informal development, or continue holding ballots to attempt to reach consensus on the proposed standard. If the Reliability Standard is approved, the Reliability Standard shall be posted and presented to the Board of Trustees by NERC management for adoption and subsequently filed with Applicable Governmental Authorities for approval.

4.16: Board of Trustees Adoption of Reliability Standards, Implementation Plan and VRFs and VSLs

If a Reliability Standard and its associated implementation plan are approved by its ballot pool, the Board of Trustees shall consider adoption of that Reliability Standard and its associated implementation plan and shall direct the standard to be filed with Applicable Governmental Authorities for approval. In making its decision, the Board shall consider the results of the balloting and unresolved dissenting opinions. The Board shall adopt or reject a Reliability Standard and its implementation plan, but shall not modify a proposed Reliability Standard. If the Board chooses not to adopt a Reliability Standard, it shall provide its reasons for not doing so.

The board shall consider approval of the VRFs and VSLs associated with a reliability standard. In making its determination, the board shall consider the following:

- The Standards Committee shall present the results of the non-binding poll conducted and a summary of industry comments received on the final posting of the proposed VRFs and VSLs.
- NERC Staff shall present a set of recommended VRFs and VSLs that considers the views of the standard drafting team, stakeholder comments received on the draft VRFs and VSLs during the posting for comment process, the non-binding poll results, appropriate governmental agency rules and directives, and VRF and VSL assignments for other Reliability Standards to ensure consistency and relevance across the entire spectrum of Reliability Standards.

4.17: Compliance

For a Reliability Standard to be enforceable, it shall be approved by its ballot pool, adopted by the NERC Board of Trustees, and approved by Applicable Governmental Authorities, unless otherwise approved by the NERC Board of Trustees pursuant to the NERC Rules of Procedure (*e.g*, Section 321) and approved by Applicable Governmental Authorities. Once a Reliability Standard is approved or otherwise made mandatory by Applicable Governmental Authorities, all persons and organizations subject to jurisdiction of the ERO will be required to comply with the Reliability Standard in accordance with applicable statutes, regulations, and agreements.

4.18: Withdrawal of a Reliability Standard, Interpretation, or Definition

The term "withdrawal" as used herein, refers to the discontinuation of a Reliability Standard, Interpretation, Variance or definition that has been approved by the Board of Trustees and (1) has not been filed with Applicable Governmental Authorities, or (2) has been filed with, but not yet approved by, Applicable Governmental Authorities. The Standards Committee may withdraw a Reliability Standard, Interpretation or definition for good cause upon approval by the Board of Trustees. Upon approval by the Board of Trustees, NERC Staff will petition the Applicable Governmental Authorities, as needed, to allow for withdrawal. The Board of Trustees also has an independent right of withdrawal that is unaffected by the terms and conditions of this Section.

4.19: Retirement of a Reliability Standard, Interpretation, or Definition

The term "retirement" refers to the discontinuation of a Reliability Standard, Interpretation or definition that has been approved by Applicable Governmental Authorities. A Reliability Standard, Variance or Definition may be retired when it is superseded by a revised version, and in such cases the retirement of

the earlier version is to be noted in the implementation plan presented to the ballot pool for approval and the retirement shall be considered approved by the ballot pool upon ballot pool approval of the revised version.

Upon identification of a need to retire a Reliability Standard, Variance, Interpretation or definition, where the item will not be superseded by a new or revised version, a SAR containing the proposal to retire a Reliability Standard, Variance, Interpretation or definition will be posted for a comment period and ballot in the same manner as a Reliability Standard. The proposal shall include the rationale for the retirement and a statement regarding the impact of retirement on the reliability of the Bulk Power System. Upon approval by the Board of Trustees, NERC Staff will petition the Applicable Governmental Authorities to allow for retirement.

Section 5.0: Process for Developing a Defined Term

NERC maintains a glossary of approved terms, entitled the *Glossary of Terms Used in NERC Reliability Standards*[24] ("Glossary of Terms"). The Glossary of Terms includes terms that have been through the formal approval process and are used in one or more NERC Reliability Standards. Definitions shall not contain statements of performance Requirements. The Glossary of Terms is intended to provide consistency throughout the Reliability Standards.

There are several methods that can be used to add, modify or retire a defined term used in a continent-wide Reliability Standard.

- Anyone can use a Standard Authorization Request ("SAR") to submit a request to add, modify, or retire a defined term.
- Anyone can submit a Standards Comments and Suggestions Form recommending the addition, modification, or retirement of a defined term. (The suggestion would be added to a project and incorporated into a SAR.)
- A drafting team may propose to add, modify, or retire a defined term in conjunction with the work it is already performing.

5.1: Proposals to Develop a New or Revised Definition

The following considerations should be made when considering proposals for new or revised definitions:

- Some NERC Regional Entities have defined terms that have been approved for use in Regional Reliability Standards, and where the drafting team agrees with a term already defined by a Regional Entity, the same definition should be adopted if needed to support a NERC Reliability Standard.
- If a term is used in a Reliability Standard according to its common meaning (as found in a collegiate dictionary), the term shall not be proposed for addition to the Glossary of Terms.
- If a term has already been defined, any proposal to modify or delete that term shall consider all uses of the definition in approved Reliability Standards, with a goal of determining whether the proposed modification is acceptable, and whether the proposed modification would change the scope or intent of any approved Reliability Standards.
- When practical, where NAESB has a definition for a term, the drafting team shall use the same definition to support a NERC Reliability Standard.

Any definition that is balloted separately from a proposed new or modified Reliability Standard or from a proposal for retirement of a Reliability Standard shall be accompanied by an implementation plan.

If a SAR is submitted to the NERC Reliability Standards Staff with a proposal for a new or revised definition, the Standards Committee shall consider the urgency of developing the new or revised definition and may direct NERC Staff to post the SAR immediately, or may defer posting the SAR until a later time based on its priority relative to other projects already underway or already approved for future development. If the SAR identifies a term that is used in a Reliability Standard already under revision by a drafting team, the Standards Committee may direct the drafting team to add the term to the scope of the existing project. Each time the Standards Committee accepts a SAR for a project that was not identified in the *Reliability Standards Development Plan*, the project shall be added to the list of approved projects.

[24] The latest approved version of the Glossary of Terms is posted on the NERC website on the Standards web page.

5.2: Stakeholder Comments and Approvals

Any proposal for a new or revised definition shall be processed in the same manner as a Reliability Standard and quality review shall be conducted in parallel with this process. Once authorized by the Standards Committee, the proposed definition and its implementation plan shall be posted for at least one formal stakeholder comment period and shall be balloted in the same manner as a Reliability Standard. If a new or revised definition is proposed by a drafting team, that definition may be balloted separately from the associated Reliability Standard.

Each definition that is approved by its ballot pool shall be submitted to the NERC Board of Trustees for adoption and then filed with Applicable Governmental Authorities for approval in the same manner as a Reliability Standard.

Section 6.0: Processes for Conducting Field Tests and Collecting and Analyzing Data

While most drafting teams can develop their Reliability Standards without the need to conduct any field tests and without the need to collect and analyze data, some Reliability Standard development efforts may require field tests to analyze data and validate concepts in the development of Reliability Standards.

There are two types of field tests – tests of concepts and tests of requirements.

6.1: Field Tests and Data Analysis for Validation of Concepts

Field tests or collection and analysis of data to validate concepts that support the development of Requirements should be conducted before the SAR for a project is finalized. If an entity wants to test a technical concept in support of a proposal for a new or revised Reliability Standard, the entity should either work with one of NERC's technical committees in collecting and analyzing the data or in conducting the field test, or the entity should submit a SAR with a request to collect and analyze data or conduct a field test to validate the concept prior to developing a new or revised Reliability Standard. The request to collect and analyze data or conduct a field test should include, at a minimum, either the data collection and analysis or field test plan, the implementation schedule, and an expectation for periodic updates of the analysis of the results. If the SAR sponsor has not collected and analyzed the data or conducted the field test, the Standards Committee may solicit support from NERC's technical committees or others in the industry. The results of the data collection and analysis or field test shall then be used to determine whether to add the SAR to the list of projects in the Reliability Standard Development Plan.

If a drafting team finds that it needs to collect and analyze data or conduct a field test of a concept that was not identified when the SAR was accepted, then the Standards Committee may direct the team to withdraw the SAR until the data has been collected and analyzed or until the field test has been conducted and the industry has had an opportunity to review the results for the impact on the scope of the proposed project.

6.2: Field Tests and Data Analysis for Validation of Requirements

If a drafting team wants to conduct a field test or collect and analyze data to validate its proposed Requirements in a Reliability Standard, the team shall first obtain approval from the Standards Committee.[25] Drafting teams are not required to collect and analyze data or to conduct a field test to validate a Reliability Standard.

The request should include at a minimum the data collection and analysis or field test plan, the implementation schedule, and an expectation for periodic updates of the results. When authorizing a drafting team to collect and analyze data or to conduct a field test of one or more Requirements, the Standards Committee may request inputs on technical matters related from NERC's technical committees or industry experts, and may request the assistance of the Compliance Monitoring and Enforcement Program. All data collection and analysis and all field tests shall be concluded and the results incorporated into the Reliability Standard Requirements as necessary before proceeding to the formal comment period and subsequent balloting.

[25] The Process for Approving Data Collection and Analysis and Field Tests Associated with a Reliability Standard is posted on the Reliability Standards Resources web page.

6.3: Communication and Coordination for All Types of Field Tests and Data Analyses

If the conduct of a field test (concepts or Requirements) or data collection and analysis could render Registered Entities incapable of complying with the current Requirements of an approved Reliability Standard that is undergoing revision, the drafting team shall request a temporary waiver from compliance to those Requirements for entities participating in the field test. Upon request, the Standards Committee shall seek approval for the waiver from the Compliance Monitoring and Enforcement Program prior to the approval of the field test or data collection and analysis.

Once a plan for a field test or a plan for data collection and analysis is approved, the NERC Reliability Standards Staff shall, under the direction of the Standards Committee, coordinate the implementation of the field test or data collection and analysis and shall provide official notice to the participants in the field test or data collection of any applicable temporary waiver to compliance with specific noted Requirements. The drafting team conducting the field test shall provide periodic updates on the progress of the field tests or data collection and analysis to the Standards Committee. The Standards Committee has the right to curtail a field test or data collection and analysis that is not implemented in accordance with the approved plan.

The field test plan or data collection and analysis plan, its approval, its participants, and all reports and results shall be publicly posted for stakeholder review on the Reliability Standards web page.

If a drafting team conducts or participates in a field test or in data collection and analysis (of concepts or Requirements), it shall provide a final report that identifies the results and how those results will be used.

Section 7.0: Process for Developing an Interpretation

A valid Interpretation request is one that requests additional clarity about one or more Requirements in approved NERC Reliability Standards, but does not request approval as to how to comply with one or more Requirements. A valid Interpretation response provides additional clarity about one or more Requirements, but does not expand on any Requirement and does not explain how to comply with any Requirement. Any entity that is directly and materially affected by the reliability of the North American Bulk Power Systems may request an Interpretation of any Requirement in any continent-wide Reliability Standard that has been adopted by the NERC Board of Trustees. Interpretations will only be provided for Board of Trustees-approved Reliability Standards *i.e.* (i) the current effective version of a Reliability Standard; or (ii) a version of a Reliability Standard with a future effective date.

An Interpretation may only clarify or interpret the Requirements of an approved Reliability Standard, including, if applicable, any attachment referenced in the Requirement being clarified. No other elements of an approved Reliability Standard are subject to Interpretation.

The entity requesting the Interpretation shall submit a *Request for Interpretation* form[26] to the NERC Reliability Standards Staff explaining the clarification required, the specific circumstances surrounding the request, and the impact of not having the Interpretation provided. The NERC Reliability Standards and Legal Staffs shall review the request for interpretation to determine whether it meets the requirements for a valid interpretation. Based on this review, the NERC Standards and Legal Staffs shall make a recommendation to the Standards Committee whether to accept the request for Interpretation and move forward in responding to the Interpretation request.

For example, an Interpretation request may be rejected where it:

(1) Requests approval of a particular compliance approach;
(2) Identifies a gap or perceived weakness in the approved Reliability Standard;
(3) Where an issue can be addressed by an active standard drafting team;
(4) Where it requests clarification of any element of a Reliability Standard other than a Requirement;
(5) Where a question has already been addressed in the record;
(6) Where the Interpretation identifies an issue and proposes the development of a new or modified Reliability Standard, (such issues should be addressed via submission of a SAR);
(7) Where an Interpretation seeks to expand the scope of a Reliability Standard; or
(8) Where the meaning of a Reliability Standard is plain on its face.

If the Standards Committee rejects the Interpretation request, it shall provide a written explanation for rejecting the Interpretation to the entity requesting the Interpretation within 10 business days of the decision to reject. If the Standards Committee accepts the Interpretation request, the NERC Standards Staff shall (i) form a ballot pool and (ii) assemble an Interpretation drafting team with the relevant expertise to address the interpretation for approval by the Standards Committee. As soon as practical, the team shall develop a "final draft" Interpretation providing the requested clarity.

Interpretations will be balloted in the same manner as Reliability Standards.

[26] The *Request for Interpretation* form is posted on the NERC Standards web page.

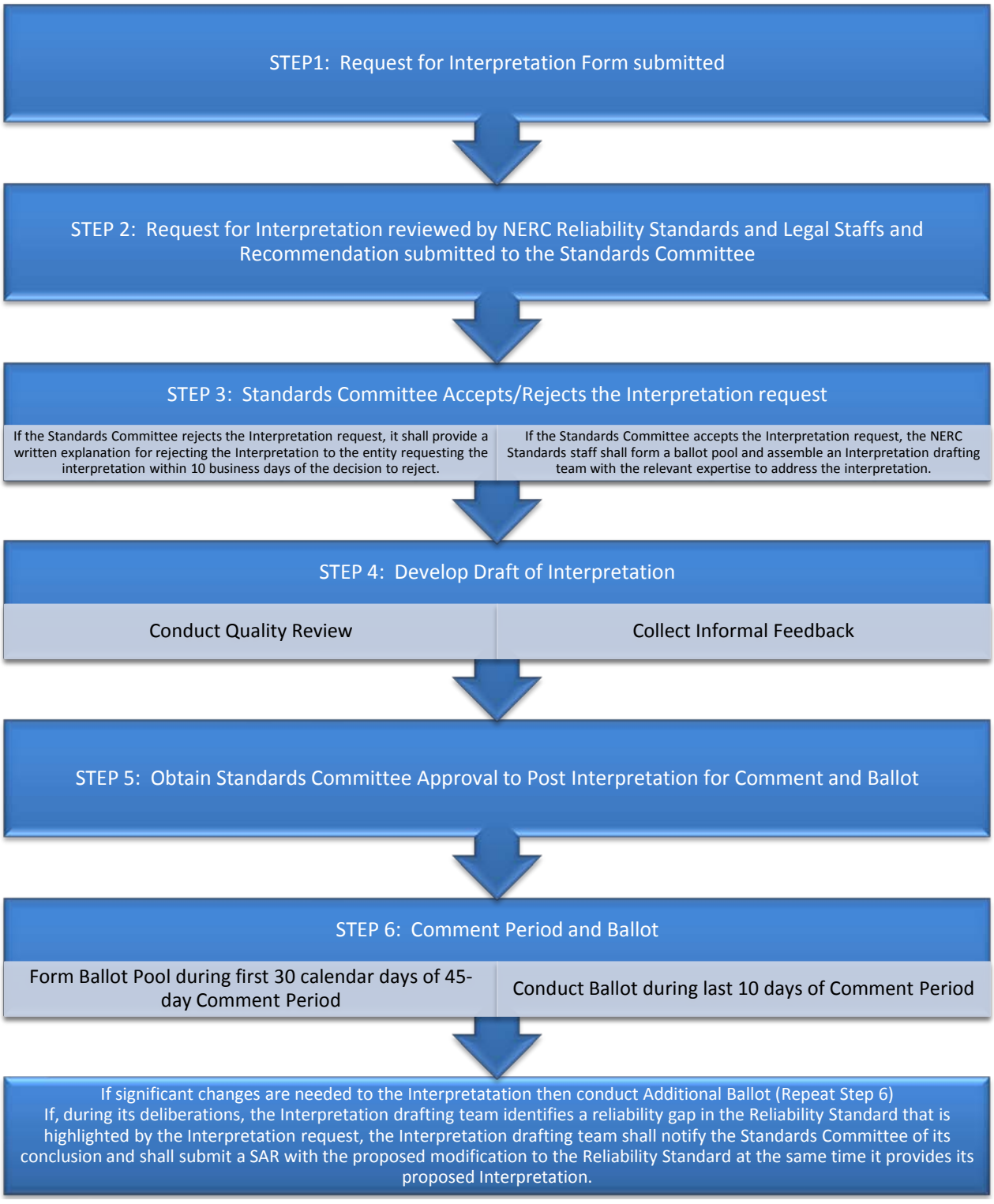
If stakeholder comments indicate that there is not a consensus for the Interpretation, and the Interpretation drafting team cannot revise the Interpretation without violating the basic expectations outlined above, the Interpretation drafting team shall notify the Standards Committee of its conclusion and may submit a SAR with the proposed modification to the Reliability Standard. The entity that requested the Interpretation shall be notified and the disposition of the Interpretation shall be posted.

If, during its deliberations, the Interpretation drafting team identifies a reliability gap in the Reliability Standard that is highlighted by the Interpretation request, the Interpretation drafting team shall notify the Standards Committee of its conclusion and may submit a SAR with the proposed modification to the Reliability Standard at the same time it provides its proposed Interpretation.

The NERC Reliability Standards and Legal Staffs shall review the final Interpretation to determine whether it has met the requirements for a valid Interpretation. Based on this review, the NERC Standards and Legal Staffs shall make a recommendation to the NERC Board of Trustees regarding adoption.

If approved by its ballot pool, the Interpretation shall be forwarded to the NERC Board of Trustees for adoption.[27] If an Interpretation drafting team proposes a modification to a Reliability Standard as part of its work in developing an Interpretation, the Board of Trustees shall be notified of this proposal at the time the Interpretation is submitted for adoption. Following adoption by the Board of Trustees, NERC Staff shall file the Interpretation for approval by Applicable Governmental Authorities and the Interpretation shall become effective when approved by those Applicable Governmental Authorities. The Interpretation shall stand until such time as the Interpretation can be incorporated into a future revision of the Reliability Standard or the Interpretation is retired due to a future modification of the applicable Requirement.

[27] NERC will maintain a record of all interpretations associated with each standard on the Reliability Standards page of the NERC website.


STEP1: Request for Interpretation Form submitted
STEP 2: Request for Interpretation reviewed by NERC Reliability Standards and Legal Staffs and Recommendation submitted to the Standards Committee
STEP 3: Standards Committee Accepts/Rejects the Interpretation request
If the Standards Committee rejects the Interpretation request, it shall provide a written explanation for rejecting the Interpretation to the entity requesting the interpretation within 10 business days of the decision to reject.
If the Standards Committee accepts the Interpretation request, the NERC Standards staff shall form a ballot pool and assemble an Interpretation drafting team with the relevant expertise to address the interpretation.
STEP 4: Develop Draft of Interpretation
Conduct Quality Review
Collect Informal Feedback
STEP 5: Obtain Standards Committee Approval to Post Interpretation for Comment and Ballot
STEP 6: Comment Period and Ballot
Form Ballot Pool during first 30 calendar days of 45-day Comment Period
Conduct Ballot during last 10 days of Comment Period
If significant changes are needed to the Interpretatation then conduct Additional Ballot (Repeat Step 6)
If, during its deliberations, the Interpretation drafting team identifies a reliability gap in the Reliability Standard that is highlighted by the Interpretation request, the Interpretation drafting team shall notify the Standards Committee of its conclusion and shall submit a SAR with the proposed modification to the Reliability Standard at the same time it provides its proposed Interpretation.

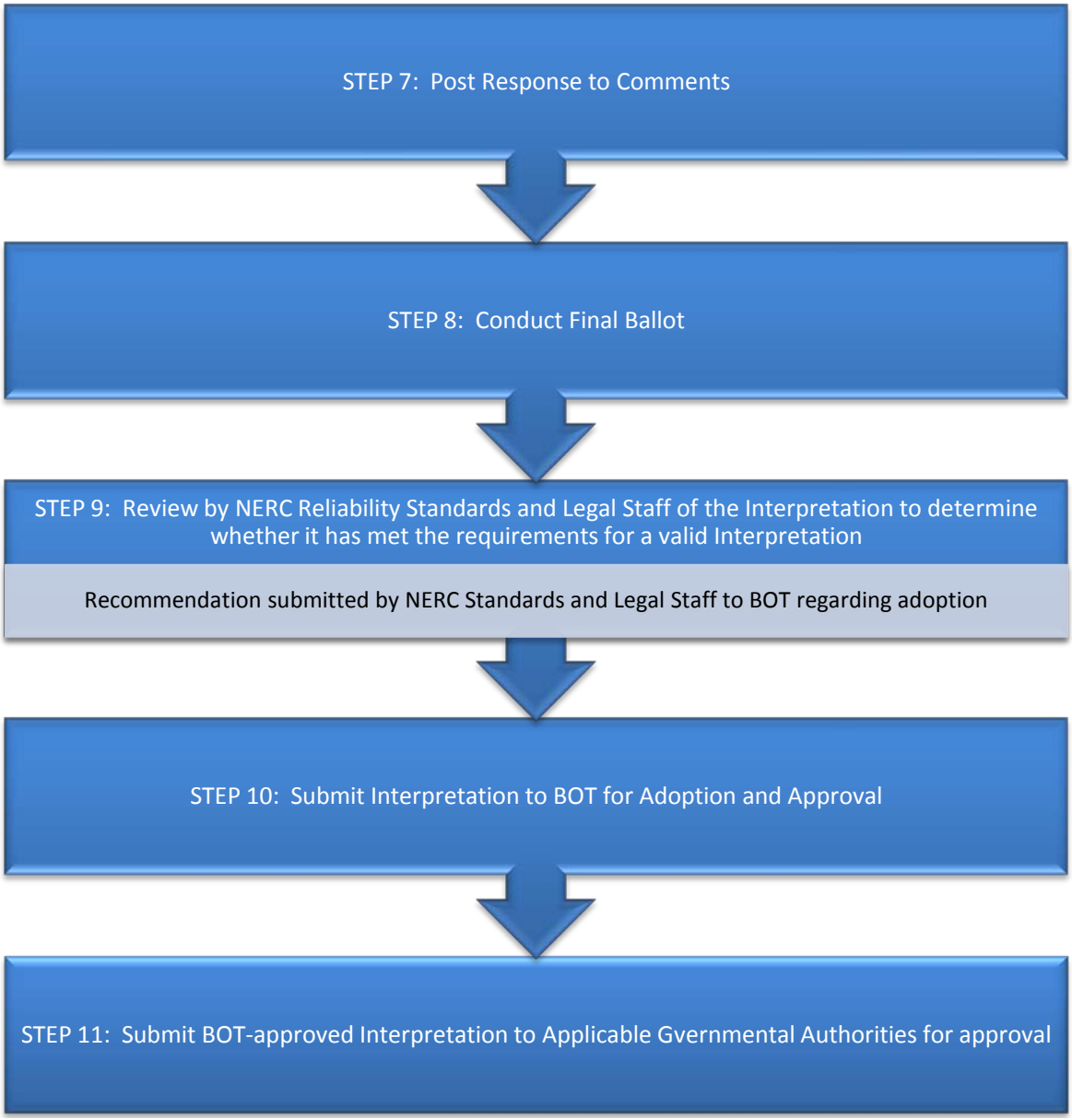


FIGURE 2: Process for Developing an Interpretation

Section 8.0: Process for Appealing an Action or Inaction

Any entity that has directly and materially affected interests and that has been or will be adversely affected by any procedural action or inaction related to the development, approval, revision, reaffirmation, retirement or withdrawal of a Reliability Standard, definition, Variance, associated implementation plan, or Interpretation shall have the right to appeal. This appeals process applies only to the NERC Reliability Standards processes as defined in this manual, not to the technical content of the Reliability Standards action.

The burden of proof to show adverse effect shall be on the appellant. Appeals shall be made in writing within 30 days of the date of the action purported to cause the adverse effect, except appeals for inaction, which may be made at any time. The final decisions of any appeal shall be documented in writing and made public.

The appeals process provides two levels, with the goal of expeditiously resolving the issue to the satisfaction of the participants.

8.1: Level 1 Appeal

Level 1 is the required first step in the appeals process. The appellant shall submit (to the Director of Standards) a complaint in writing that describes the procedural action or inaction associated with the Reliability Standards process. The appellant shall describe in the complaint the actual or potential adverse impact to the appellant. Assisted by NERC Staff and industry resources as needed, the Director of Standards shall prepare a written response addressed to the appellant as soon as practical but not more than 45 days after receipt of the complaint. If the appellant accepts the response as a satisfactory resolution of the issue, both the complaint and response shall be made a part of the public record associated with the Reliability Standard.

8.2: Level 2 Appeal

If after the Level 1 Appeal the appellant remains unsatisfied with the resolution, as indicated by the appellant in writing to the Director of Standards, the Director of Standards shall convene a Level 2 Appeals Panel. This panel shall consist of five members appointed by the Board of Trustees. In all cases, Level 2 Appeals Panel members shall have no direct affiliation with the participants in the appeal.

The NERC Reliability Standards Staff shall post the complaint and other relevant materials and provide at least 30 days notice of the meeting of the Level 2 Appeals Panel. In addition to the appellant, any entity that is directly and materially affected by the procedural action or inaction referenced in the complaint shall be heard by the panel. The panel shall not consider any expansion of the scope of the appeal that was not presented in the Level 1 Appeal. The panel may, in its decision, find for the appellant and remand the issue to the Standards Committee with a statement of the issues and facts in regard to which fair and equitable action was not taken. The panel may find against the appellant with a specific statement of the facts that demonstrate fair and equitable treatment of the appellant and the appellant's objections. The panel may not, however, revise, approve, disapprove, or adopt a Reliability Standard, definition, Variance or Interpretation or implementation plan as these responsibilities remain with the ballot pool and Board of Trustees respectively. The actions of the Level 2 Appeals Panel shall be publicly posted.

In addition to the foregoing, a procedural objection that has not been resolved may be submitted to the Board of Trustees for consideration at the time the Board decides whether to adopt a particular Reliability Standard, definition, Variance or Interpretation. The objection shall be in writing, signed by an officer of

the objecting entity, and contain a concise statement of the relief requested and a clear demonstration of the facts that justify that relief. The objection shall be filed no later than 30 days after the announcement of the vote by the ballot pool on the Reliability Standard in question.

Section 9.0: Process for Developing a Variance

A Variance is an approved, alternative method of achieving the reliability intent of one or more Requirements in a Reliability Standard. No Regional Entity or Bulk Power System owner, operator, or user shall claim a Variance from a NERC Reliability Standard without approval of such a Variance through the relevant Reliability Standard approval procedure for the Variance. Each Variance from a NERC Reliability Standard that is approved by NERC and Applicable Governmental Authorities shall be made an enforceable part of the associated NERC Reliability Standard.

NERC's drafting teams shall aim to develop Reliability Standards with Requirements that apply on a continent-wide basis, minimizing the need for Variances while still achieving the Reliability Standard's reliability objectives. If one or more Requirements cannot be met or complied with as written because of a physical difference in the Bulk Power System or because of an operational difference (such as a conflict with a federally or provincially approved tariff), but the Requirement's reliability objective can be achieved in a different fashion, an entity or a group of entities may pursue a Variance from one or more Requirements in a continent-wide Reliability Standard. It is the responsibility of the entity that needs a Variance to identify that need and initiate the processing of that Variance through the submittal of a SAR[28] that includes a clear definition of the basis for the Variance.

There are two types of Variances – those that apply on an Interconnection-wide basis, and those that apply to one or more entities on less than an Interconnection-wide basis.

9.1: Interconnection-wide Variances

Any Variance from a NERC Reliability Standard Requirement that is proposed to apply to Registered Entities within a Regional Entity organized on an Interconnection-wide basis shall be considered an Interconnection-wide Variance and shall be developed through that Regional Entity's NERC-approved Regional Reliability Standards development procedure.

While an Interconnection-wide Variance may be developed through the associated Regional Reliability Standards development process, Regional Entities are encouraged to work collaboratively with existing continent-wide drafting teams to reduce potential conflicts between the two efforts.

An Interconnection-wide Variance from a NERC Reliability Standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with other applicable standards of governmental authorities shall be made part of the associated NERC Reliability Standard. NERC shall rebuttably presume that an Interconnection-wide Variance from a NERC Reliability Standard that is developed, in accordance with a Regional Reliability Standards development procedure approved by NERC, by a Regional Entity organized on an Interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest.

9.2: Variances that Apply on Less than an Interconnection-wide Basis

Any Variance from a NERC Reliability Standard Requirement that is proposed to apply to one or more entities but less than an entire Interconnection (*e.g.*, a Variance that would apply to a regional transmission organization or particular market or to a subset of Bulk Power System owners, operators, or users), shall be considered a Variance. A Variance may be requested while a Reliability Standard is under development or a Variance may be requested at any time after a Reliability Standard is approved. Each request for a Variance shall be initiated through a SAR, and processed and approved in the same

[28] A sample of a SAR that identifies the need for a Variance and a sample Variance are posted as resources on the Reliability Standards Resources web page.

manner as a continent-wide Reliability Standard, using the Reliability Standards development process defined in this manual.

Section 10.0: Processes for Developing a Reliability Standard Related to a Confidential Issue

While it is NERC's intent to use its ANSI-accredited Reliability Standards development process for developing its Reliability Standards, NERC has an obligation as the ERO to ensure that there are Reliability Standards in place to preserve the reliability of the interconnected Bulk Power Systems throughout North America. When faced with a national security emergency situation, NERC may use one of the following special processes to develop a Reliability Standard that addresses an issue that is confidential. Reliability Standards developed using one of the following processes shall be called, "special Reliability Standards" and shall not be filed with ANSI for approval as American National Standards.

The NERC Board of Trustees may direct the development of a new or revised Reliability Standard to address a national security situation that involves confidential issues. These situations may involve imminent or long-term threats. In general, these Board directives will be driven by information from the President of the United States of America or the Prime Minister of Canada or a national security agency or national intelligence agency of either or both governments indicating (to the ERO) that there is a national security threat to the reliability of the Bulk Power System.[29]

There are two special processes for developing Reliability Standards responsive to confidential issues – one process where the confidential issue is "imminent," and one process where the confidential issue is "not imminent."

10.1: Process for Developing Reliability Standards Responsive to Imminent, Confidential Issues
If the NERC Board of Trustees directs the immediate development of a new or revised Reliability Standard to address a confidential national security emergency situation, the NERC Reliability Standards Staff shall develop a SAR, form a ballot pool (to vote on the Reliability Standard and its implementation plan) and assemble a slate of pre-defined subject matter experts as a proposed drafting team for approval by the Standards Committee's officers. All members of the Registered Ballot Body shall have the opportunity to join the ballot pool.

10.2: Drafting Team Selection
The Reliability Standard drafting team selection process shall be limited to just those candidates who have already been identified as having the appropriate security clearance, the requisite technical expertise, and either have signed or are willing to sign a strict confidentiality agreement.

10.3: Work of Drafting Team
The Reliability Standard drafting team shall perform all its work under strict security and confidential rules. The Reliability Standard drafting team shall develop the new or revised Reliability Standard and its implementation plan.

The Reliability Standard drafting team shall review its work, to the extent practical, as it is being developed with officials from the appropriate governmental agencies in the U.S. and Canada, under strict security and confidentiality rules.

[29] The NERC Board may direct the immediate development and issuance of a Level 3 (Essential Action) alert and then may also direct the immediate development of a new or revised Reliability Standard.

10.4: Formal Stakeholder Comment & Ballot Window
The draft Reliability Standard and its implementation plan shall be distributed for a formal comment period, under strict confidentiality rules, only to those entities that are listed in the NERC Compliance Registry to perform one of the functions identified in the applicability section of the Reliability Standard and have identified individuals from their organizations that have signed confidentiality agreements with NERC.[30] At the same time, the Reliability Standard shall be distributed to the members of the ballot pool for review and ballot. The NERC Reliability Standards Staff shall not post or provide the ballot pool with any confidential background information.

The drafting team, working with the NERC Reliability Standards Staff, shall consider and respond to all comments, make any necessary conforming changes to the Reliability Standard and its implementation plan, and shall distribute the comments, responses and any revision to the same population as received the initial set of documents for formal comment and ballot.

10.5: Board of Trustee Actions
Each Reliability Standard and implementation plan developed through this process shall be submitted to the NERC Board of Trustees for adoption.

10.6: Governmental Approvals
All approved documents shall be filed for approval with Applicable Governmental Authorities.

[30] In this phase of the process, only the proposed Reliability Standard shall be distributed to those entities expected to comply, not the rationale and justification for the Reliability Standard. Only the special drafting team members, who have the appropriate security credentials, shall have access to this rationale and justification.

10.7: Developing a Reliability Standard Responsive to an Imminent, Confidential Issue

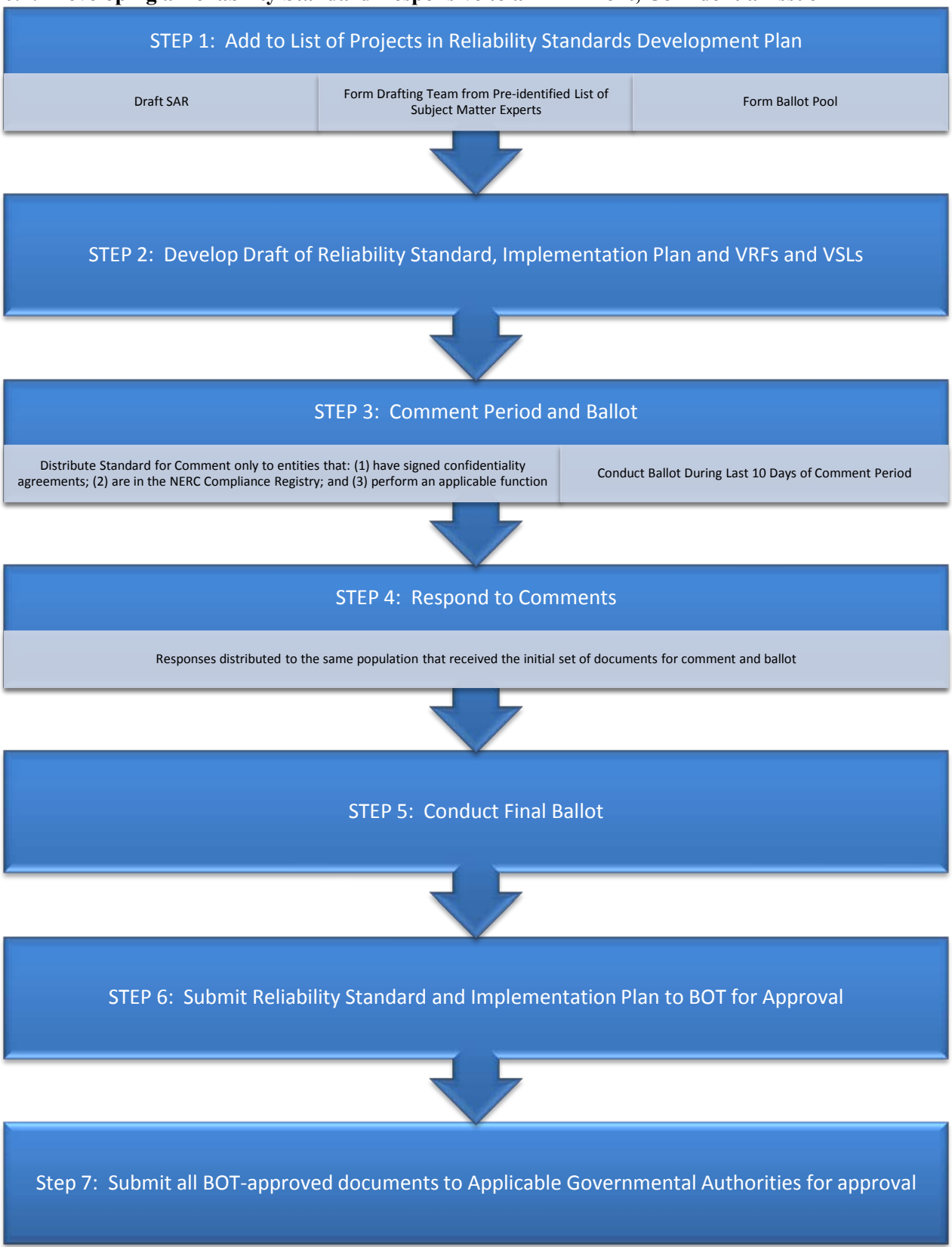


FIGURE 3: Process for Developing a Standard Responsive to an Imminent, Confidential Issue

10.8: Process for Developing Reliability Standards Responsive to Non-imminent, Confidential Issues

If the NERC Board of Trustees directs the immediate development of a new or revised Reliability Standard to address a confidential national security emergency situation, the NERC Reliability Standards Staff shall develop a SAR, form a ballot pool (to vote on the Reliability Standard and its implementation plan) and assemble a slate of pre-defined subject matter experts as a proposed drafting team for approval by the Standards Committee's officers. All members of the Registered Ballot Body shall have the opportunity to join the ballot pool.

10.9: Drafting Team Selection

The drafting team selection process shall be limited to just those candidates who have already been identified as having the appropriate security clearance, the requisite technical expertise, and either have signed or are willing to sign a strict confidentiality agreement.

10.10: Work of Drafting Team

The drafting team shall perform all its work under strict security and confidential rules. The Reliability Standard drafting team shall develop the new or revised Reliability Standard and its implementation plan.

The drafting team shall review its work, to the extent practical, as it is being developed with officials from the Applicable Governmental Authorities, under strict security and confidentiality rules.

10.11: Formal Stakeholder Comment & Ballot Window

The draft Reliability Standard and its implementation plan shall be distributed for a formal comment period, under strict confidentiality rules, only to those entities that are listed in the NERC Compliance Registry to perform one of the functions identified in the applicability section of the Reliability Standard and have identified individuals from their organizations that have signed confidentiality agreements with NERC.[31] At the same time, the Reliability Standard shall be distributed to the members of the ballot pool for review and ballot. The NERC Reliability Standards Staff shall not post or provide the ballot pool with any confidential background information.

10.12: Revisions to Reliability Standard, Implementation Plan and VRFs and VSLs

The drafting team, working with the NERC Reliability Standards Staff, shall work to refine the Reliability Standard, implementation plan and VRFs and VSLs in the same manner as for a new Reliability Standard following the "normal" Reliability Standards development process described earlier in this manual with the exception that distribution of the comments, responses, and new drafts shall be limited to those entities that are in the ballot pool and those entities that are listed in the NERC Compliance Registry to perform one of the functions identified in the applicability section of the Reliability Standard and have identified individuals from their organizations that have signed confidentiality agreements with NERC.

10.13: Board of Trustee Action

Each Reliability Standard, implementation plan, and the associated VRFs and VSLs developed through this process shall be submitted to the NERC Board of Trustees for adoption.

10.14: Governmental Approvals

All BOT-approved documents shall be filed for approval with Applicable Governmental Authorities.

[31] In this phase of the process, only the proposed Reliability Standard shall be distributed to those entities expected to comply, not the rationale and justification for the Reliability Standard. Only the special drafting team members, who have the appropriate security credentials, shall have access to this rationale and justification.

Developing a Reliability Standard Responsive to a Non-imminent, Confidential Issue

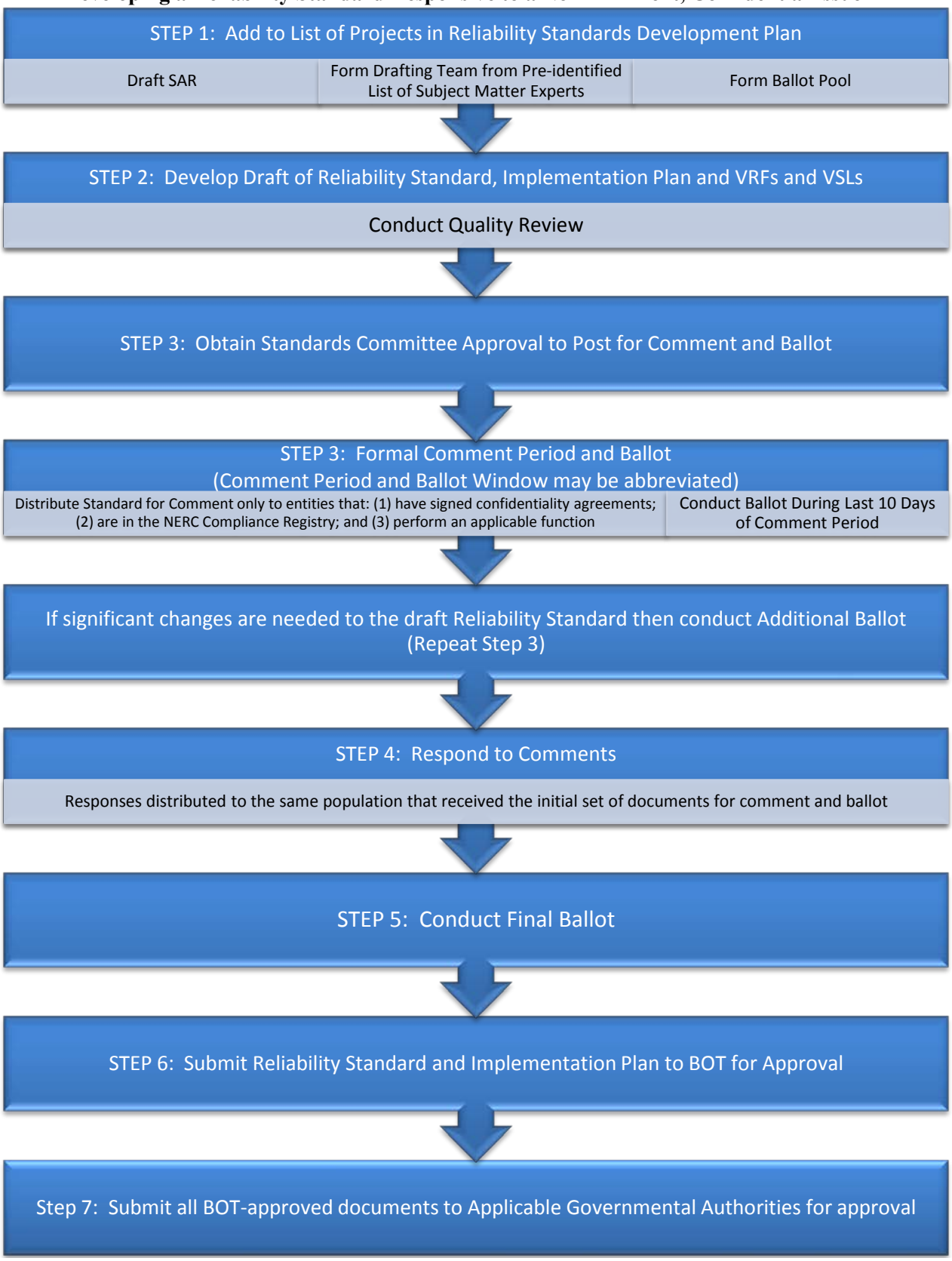


FIGURE 4: Developing a Standard Responsive to a Non-Imminent, Confidential Issue

Section 11.0: Process for Approving Supporting Documents

The following types of documents are samples of the types of supporting documents that may be developed to enhance stakeholder understanding and implementation of a Reliability Standard. These documents may explain or facilitate implementation of Reliability Standards but do not themselves contain mandatory Requirements subject to compliance review. Any Requirements that are mandatory shall be incorporated into the Reliability Standard in the Reliability Standard development process.

While most supporting documents are developed by the standard drafting team working to develop the associated Reliability Standard, any entity may develop a supporting document associated with a Reliability Standard.

The Standards Committee shall authorize the posting of all supporting references[32] that are linked to an approved Reliability Standard. Prior to granting approval to post a supporting reference with a link to the associated Reliability Standard, the Standards Committee shall verify that the document has had stakeholder review to verify the accuracy of the technical content. While the Standards Committee has the authority to approve the posting of each such reference, stakeholders, not the Standards Committee, verify the accuracy of the document's contents.

Type of Document	Description
Reference	Descriptive, technical information or analysis or explanatory information to support the understanding and interpretation of a Reliability Standard. A standard reference may support the implementation of a Reliability Standard or satisfy another purpose consistent with the reliability and market interface principles.
Guideline	Recommended process that identifies a method of meeting a Requirement under specific conditions.
Supplement	Data forms, pro forma documents, and associated instructions that support the implementation of a Reliability Standard.
Training Material	Documents that support the implementation of a Reliability Standard.
Procedure	Step-wise instructions defining a particular process or operation. Procedures may support the implementation of a Reliability Standard or satisfy another purpose consistent with the reliability and market interface principles.
White Paper	An informal paper stating a position or concept. A white paper may be used to propose preliminary concepts for a Reliability Standard or one of the documents above.

[32] The Standards Committee's Procedure for Approving the Posting of Reference Documents is posted on the Reliability Standards Resources web page.

Section 12.0: Process for Correcting Errata

From time to time, an error may be discovered in a Reliability Standard. Such errors may be corrected (i) following a Final Ballot prior to Board of Trustees adoption, (ii) following Board of Trustees adoption prior to filing with Applicable Governmental Authorities; and (iii) following filing with Applicable Governmental Authorities. If the Standards Committee agrees that the correction of the error does not change the scope or intent of the associated Reliability Standard, and agrees that the correction has no material impact on the end users of the Reliability Standard, then the correction shall be filed for approval with Applicable Governmental Authorities as appropriate. The NERC Board of Trustees has resolved to concurrently approve any errata approved by the Standards Committee.

Section 13.0: Process for Conducting Periodic Reviews of Reliability Standards

All Reliability Standards shall be reviewed at least once every ten years from the effective date of the Reliability Standard or the date of the latest Board of Trustees adoption to a revision of the Reliability Standard, whichever is later. If a Reliability Standard is approved by ANSI as an American National Standard, it shall be reviewed at least once every five years from the effective date of the Reliability Standard or the date of the latest Board of Trustees adoption to a revision of the Reliability Standard, whichever is later.

The *Reliability Standards Development Plan* shall include projects that address this five or ten-year review of Reliability Standards.

- If a Reliability Standard is nearing its five or ten-year review and has issues that need resolution, then the *Reliability Standards Development Plan* shall include a project for the complete review and associated revision of that Reliability Standard that includes addressing all outstanding governmental directives, all approved Interpretations, and all unresolved issues identified by stakeholders.
- If a Reliability Standard is nearing its five or ten-year review and there are no outstanding governmental directives, Interpretations, or unresolved stakeholder issues associated with that Reliability Standard, then the Reliability *Standards Development Plan* shall include a project solely for the "five-year review" of that Reliability Standard.

For a project that is focused solely on the five-year review, the Standards Committee shall appoint a review team of subject matter experts to review the Reliability Standard and recommend whether the American National Standard Institute-approved Reliability Standard should be reaffirmed, revised, or withdrawn. Each review team shall post its recommendations for a 45 calendar day formal stakeholder comment period and shall provide those stakeholder comments to the Standards Committee for consideration.

- If a review team recommends reaffirming a Reliability Standard, the Standards Committee shall submit the reaffirmation to the Board of Trustees for adoption and then to Applicable Governmental Authorities for approval. Reaffirmation does not require approval by stakeholder ballot.
- If a review team recommends modifying, or retiring a Reliability Standard, the team shall develop a SAR with such a proposal and the SAR shall be submitted to the Standards Committee for prioritization as a new project. Each existing Reliability Standard recommended for modification, or retirement shall remain in effect in accordance with the associated implementation plan until the action to modify or withdraw the Reliability Standard is approved by its ballot pool, adopted by the Board of Trustees, and approved by Applicable Governmental Authorities.

In the case of reaffirmation of a Reliability Standard, the Reliability Standard shall remain in effect until the next five or ten-year review or until the Reliability Standard is otherwise modified or withdrawn by a separate action.

Section 14.0: Public Access to Reliability Standards Information

14.1: Online Reliability Standards Information System

The NERC Reliability Standards Staff shall maintain an electronic copy of information regarding currently proposed and currently in effect Reliability Standards. This information shall include current Reliability Standards in effect, proposed revisions to Reliability Standards, and proposed new Reliability Standards. This information shall provide a record, for at a minimum the previous five years, of the review and approval process for each Reliability Standard, including public comments received during the development and approval process.

14.2: Archived Reliability Standards Information

The NERC Staff shall maintain a historical record of Reliability Standards information that is no longer maintained online. Archived information shall be retained indefinitely as practical, but in no case less than five years or one complete standard cycle from the date on which the Reliability Standard was no longer in effect. Archived records of Reliability Standards information shall be available electronically within 30 days following the receipt by the NERC Reliability Standards Staff of a written request.

Section 15.0: Process for Updating Standard Processes

15.1: Requests to Revise the Standard Processes Manual

Any person or entity may submit a request to modify one or more of the processes contained within this manual. The Standards Committee shall oversee the handling of each request. The Standards Committee shall prioritize all requests, merge related requests, and respond to each sponsor within 30 calendar days.

The Standards Committee shall post the proposed revisions for a 45 (calendar) day formal comment period. Based on the degree of consensus for the revisions, the Standards Committee shall:

a. Submit the revised process or processes for ballot pool approval;
b. Repeat the posting for additional inputs after making changes based on comments received;
c. Remand the proposal to the sponsor for further work; or
d. Reject the proposal.

The Registered Ballot Body shall be represented by a ballot pool. The ballot procedure shall be the same as that defined for approval of a Reliability Standard, including the use of an Additional Ballot if needed. If the proposed revision is approved by the ballot pool, the Standards Committee shall submit the revised procedure to the Board for adoption. The Standards Committee shall submit to the Board a description of the basis for the changes, a summary of the comments received, and any minority views expressed in the comment and ballot process. The proposed revisions shall not be effective until approved by the NERC Board of Trustees and Applicable Governmental Authorities.

Section 16.0: Waiver

While it is NERC's intent to use its ANSI-accredited Reliability Standards development process for developing its Reliability Standards, NERC may need to develop a new or modified Reliability Standard, definition, Variance, or implementation plan under specific time constraints (such as to meet a time constrained regulatory directive) or to meet an urgent reliability issue such that there isn't sufficient time to follow all the steps in the normal Reliability Standards development process.

The Standards Committee may waive any of the provisions contained in this manual for good cause shown, but limited to the following circumstances:

- In response to a national emergency declared by the United States or Canadian government that involves the reliability of the Bulk Electric System or cyber attack on the Bulk Electric System;
- Where necessary to meet regulatory deadlines;
- Where necessary to meet deadlines imposed by the NERC Board of Trustees; or
- Where the Standards Committee determines that a modification to a proposed Reliability Standard or its Requirement(s), a modification to a defined term, a modification to an interpretation, or a modification to a variance has already been vetted by the industry through the standards development process or is so insubstantial that developing the modification through the processes contained in this manual will add significant time delay.

In no circumstances shall this provision be used to modify the requirements for achieving quorum or the voting requirements for approval of a standard.

A waiver request may be submitted to the Standards Committee by any entity or individual, including NERC committees or subgroups and NERC Staff. Prior to consideration of any waiver request, the Standards Committee must provide five business days notice to stakeholders.

Action on the waiver request will be included in the minutes of the Standards Committee. Following the approval of the Standards Committee to waive any provision of the Standard Process Manual, the Standards Committee will report this decision to the Standards Oversight and Technology Committee.[33] Actions taken pursuant to an approved waiver request will be posted on the Standard Project page and included in the next project announcement.

In addition, the Standards Committee shall report the exercise of this waiver provision to the Board of Trustees prior to adoption of the related Reliability Standard, Interpretation, definition or Variance.

Reliability Standards developed as a result of a waiver of any provision of the Standard Processes Manual shall not be filed with ANSI for approval as American National Standards.

[33] Any entity may appeal a waiver decision or any other procedural decision by the Standards Committee pursuant to Section 8.0 of the NERC Standard Processes Manual.

4.6: Conduct Quality Review

The NERC Reliability Standards Staff shall coordinate a quality review of the Reliability Standard, implementation plan, and VRFs and VSLs in parallel with the development of the Reliability Standard and implementation plan, to assess whether the documents are within the scope of the associated SAR, whether the Reliability Standard is clear and enforceable as written, and whether the Reliability Standard meets the criteria specified in NERC's Benchmarks for Excellent Standards and criteria for governmental approval of Reliability Standards. The drafting team shall consider the results of the quality review, decide upon appropriate changes, and recommend to the Standards Committee whether the documents are ready for formal posting and balloting.

The Standards Committee shall authorize posting the proposed Reliability Standard, and implementation plan for a formal comment period and ballot and the VRFs and VSLs for a non-binding poll as soon as the work flow will accommodate.

If the Standards Committee finds that any of the documents do not meet the specified criteria, the Standards Committee shall remand the documents to the drafting team for additional work.

If the Reliability Standard is outside the scope of the associated SAR, the drafting team shall be directed to either revise the Reliability Standard so that it is within the approved scope, or submit a request to expand the scope of the approved SAR. If the Reliability Standard is not clear and enforceable as written, or if the Reliability Standard does not meet the specified criteria, the Reliability Standard shall be returned to the drafting team by the Standards Committee with specific identification of any Requirement that is deemed to be unclear or unenforceable as written.

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

2015 NPCC Compliance Committee Meetings (as of 1/14/15)

January 14…conference call

February 18…conference call

March 17-18 (Tue, Weds) at NextEra, Juno Beach, FL

April 15…conference call

May 13…conference call

May 19-21 Compliance Workshop (Tue-Thurs) Newport, RI Marriott.
(Week before the Memorial Day holiday)

June 16-17 (Tues, Weds) at IESO, Toronto.

July 15…CC conference call

August 19…CC conference call

September 22, 23 (Tues, Weds)…at NPCC, NYC
(Rescheduled from 9/15-9/16 on the Jan 2015 CC Call)

October 14…CC conference call

November…no conference call

November 10-12 Compliance Workshop (Tue – Thurs) Westchester, NY
(Date moved from 11/17-11/19 in December 2014 due to GRIDEX III conflict)

December 3, 4 (Thus, Fri)…at Albany, NY Marriott– after NPCC annual meetings.

As of 1/14/15