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 #17-1
March 8, 2017 10:00 a.m. – 5:00 p.m. EST
March 9, 2017 8:00 a.m. – 12:00 p.m. EST
FRCC: Suite 600
3000 Bayport Drive
Tampa, Florida
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 February 7, 2017
NPCC Glossary of Terms, dated January 14, 2014

Introductions and Chair's Remarks

NPCC Antitrust Compliance Guidelines

Agenda Items:

1.0 Review of Agenda

2.0 RSC Meeting Minutes

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

5.1 NERC Weekly Standards Bulletin
5.2 Standards Balloting and Commenting System Enhancements Overview
5.3 PRC-012-2 Remedial Action Scheme NOPR
5.4 Distributed Energy Resource Report February 2017
5.5 DOE Proposed Rule – Grid Security Emergency
5.6 Lack of Quorum at FERC and Potential Impact

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	3/8/17 Call-In
Project 2013-03 Geomagnetic Disturbance Mitigation	1/20/17 (I)	NA	Mark Olson	1:00PM
Project 2016-03 Cyber Security Supply Chain Management	3/6/17 (F)	3/6/17 (I)	Mark Olson	1:15PM
Project 2016-02 Modifications to CIP Standards	1/25/17 (F)	2/8/17 (F)	Al McMeekin	1:30PM
Project 2015-08 Emergency Operations	1/6/17 (F)	2/2/17 (F)	Laura Anderson	2:00PM
Project 2015-10 Single Points of Failure TPL-001	DT Nominations		Soo Jin Kim	2:15PM
Project 2016-04 Modifications to PRC-025-1	10/18/16 (F)		Scott Barfield-McGinnis	2:30PM
Project 2016-EPR-02 Enhanced Periodic Review of Voltage and Reactive Standards	4/13/17 (F)		Scott Barfield-McGinnis	2:45PM
Revisions to the NERC Standard Processes Manual	10/28/15 (I)		Lauren Perotti	3:00PM
Project 2015-09 Establish and Communicate System Operating Limits	8/12/16 (I)		Darrel Richardson	3:15PM
Functional Model Advisory Group	9/7/16 (I)		Darrel Richardson	3:30PM
Project 2016-EPR-01 Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards	2/23/17 (F)		Darrel Richardson	3:45PM
Comments: (I) – Informal; (F) – Formal; (N) – Nomination Period **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

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 Automatic Underfrequency Load Shedding PRC-006-NPCC-02 status update

8.1.2 PRC-006-3 Automatic Underfrequency Load Shedding Quebec Variance status update

9.0 NPCC Non-Standards

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

9.1 Directories:

9.1.1 Directory#8 *System Restoration* – (status of CO11 review).

9.1.2 Directory#9 and #10 *Real and Reactive Capability Verification* - (status of TFCO review).

9.1.3 Directory#7 *SPS* and NPCC Glossary term SPS – (status of PRC -12-2)

9.1.4 A-10 *Classification of BPS Elements* (status of TFCP review).

9.1.5 A-01 *Criteria for Review and Approval of Documents* – (status of TFCP review).

- RSC to consider incorporating A-01 into the Directory Review and Revision Manual

9.1.6 Directory#2 *Emergency Operations* and Directory#5 *Reserve* - (status of TFCO review).

9.2 RAS Implementation/Transition

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 18th - Call	March 15th - Meeting	April 19th - Call
June 14th - Meeting	July 19th - Call	September 7th Meeting
October 18th - Call	December 6th - 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/Related%20Files%20DL/ERO_Reliability_Risk_Priorities_RISC_Reccommendations_Board_Approved_Nov_2016.pdf

13.0 NERC Items of Interest (Since last RSC Meeting)

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

13.1.1 There have been no new Lesson Learned issued since the last RSC meeting.

13.2 Alerts

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

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

13.3 Standard Committee 2017 Meeting Schedule

January 18th - Call	March 15th - WECC	April 19th – Call
June 14th – Atlanta	July 18th – Call	September 7th – MRO
October 18th – Call	December 6th - Atlanta	

14.0 Other Items of Interest

14.1 NPCC Compliance Committee (CC) Schedule

January 18th – Call	February 15th – Call	March 14-15th Meeting
April 12th – Call	May 23-25th Workshop	June 13-14th Meeting
July 12th – Call	August 16th – Call	September 19-20th Meeting
October 18th – Call	November 7-9th Workshop	December 7th Meeting

14.2 NPCC Board of Directors Meeting (BOD) 2017

February 1st - FRCC Office, Tampa, FL	March 22nd - Call	May 3rd – NPCC Office
June 1st – Call	June 28th – NPCC Office	August 2nd – Call
September 6th and 7th – Portland ME	November 1st – Call	December 6th – Boston MA

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2017 Meeting Dates

March 8th-9th, FRCC, Tampa FL
June 7th-8th, Saratoga NY
August 23rd-24th, Toronto/Montreal
October 11th-12th, Lewiston NY
December 7th, General Meeting

15.2 RSC 2017 Conference Call Schedule (calls can be schedule as needed) all Calls are planned to start at 10:00 a.m. (call: 415-655-0003 (USA) / 416-915-6530 (Canada), Guest Code 28840965)

January 20	February 3	February 17
March 24	April 7	April 21
May 5	May 19	June 16
June 30	July 14	July 28
August 11	September 8	September 22
September 30	October 27	November 10
November 24	December 22	

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 #16-6
December 8, 2016 8:00 a.m. – 5:00 p.m. EST
December 9, 2016 8:00 a.m. – 12:00 p.m. EST
Hotel Omni Mont-Royal: Room Automne
1050 Sherbrooke Street West
Montreal, Quebec H3A 2R6
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 September 29, 2016
NPCC Glossary of Terms, dated January 14, 2014

	Name	Organization	Sector (s)	Day(s)	Comment
1.	Guy Zito	Northeast Power Coordinating Council		1 & 2	
2.	Gerry Dunbar	Northeast Power Coordinating Council		1 & 2	
3.	Ruida Shu	Northeast Power Coordinating Council		1 & 2	2nd Day Via Phone
4.	Kal Ayoub	FERC	Guest	1	
5.	Howard Gugel	NERC	Guest	1	
6.	Herb Schrayshuen	Power Advisors, LLC - Proxy for NextEra Energy, LLC	4	1 & 2	
7	Michael Jones	National Grid	3	1 & 2	
8.	Joel Charlebois	AESI, Inc.	Guest	1 & 2	
9.	Kelly Silver	Consolidated Edison Co. of New York, Inc.	1, 3, 4 & 5	1 & 2	
10.	David Ramkalawan	Ontario Power Generation, Inc.	4	1 & 2	Via Phone
11.	Chris Kirby	Nalcor Energy	Guest	1	
12.	Chantal Mazza	Hydro-Québec TransÉnergie	2	1	
13.	Si Truc Phan	Hydro-Québec TransÉnergie	2	1 & 2	
14.	Navneet Singh	IESO	Guest	1 & 2	

15.	Dave Devereaux	IESO	Guest	1	
16.	Jim Grant	New York Independent System Operator	2	1 & 2	
17.	Greg Campoli	New York Independent System Operator	2	2	
18.	Payam Farahbakhsh	Hydro One Networks	1	1	
19.	Ben Wu	Orange & Rockland Utilities, Inc.	3	1	
20.	Quintin Lee	Eversource Energy	1	1 & 2	
21.	Laura Mcleod	New Brunswick Power Corporation	1	1 & 2	
22.	Brian Robinson	Utility Services, Inc.	5	1	2nd Day Via Phone
23.	Salvatore Spagnolo	New York Power Authority	4	1 & 2	
24.	Sean Bodkin	Dominion Resources Services	4	2	
25.	Michele Tondalo	The United Illuminating Company	1	1	Via Phone
26.	Vijay Puran	New York State Department of Public Service	Guest	1	Via Phone
27.	David Kigul	Independent	Guest	1	Via Phone
28.	Rita Metta	Regie de l’energie	Guest	2	
29.	Laurentia Dumitrescu	Regie de l’energie	Guest	2	
30.	Al McMeekin	NERC	Guest	1	Via Phone
31.	Mat Bunch	NERC	Guest	1	Via Phone
32.	Mark Olson	NERC	Guest	1	Via Phone
33.	Lacey Ourso	NERC	Guest	1	Via Phone
34.	Laura Anderson	NERC	Guest	1	Via Phone
35.	Jordan Mallory	NERC	Guest	1	Via Phone

Introductions and Chair’s Remarks

Guy Zito welcomed everyone to Montreal Canada, he provided a brief introduction and indicated that Mike Jones has been approved as the co-vice chair of RSC at the NPCC Board Meeting in December 2016.

NPCC Antitrust Compliance Guidelines
The NPCC Antitrust Compliance Guidelines were read by Ruida Shu.

Agenda Items:

1.0 Review of Agenda

Guy Zito reviewed the agenda with the RSC and added agenda item 5.6 and indicated Kal Ayoub from FERC ~~will do~~would provide a presentation on Federal Oversight of Electric Reliability for the RSC group.

2.0 RSC Meeting Minutes

Approval of Minutes—there was one minor grammar revision to the Final Meeting Minutes of 10-5-16.
Jim Grant made a motion for approval.
Herb Schrayshuen seconded the motion.
The Meeting Minutes were approved as revised and documented.

3.0 Drafting Team Members and Executive Tracking Summary

3.1 NPCC Members on NERC Drafting Teams
Action Item: Ruida Shu/Guy Zito will send out a note to TFSP to solicit member to support the Project 2016-04 Modifications to PRC-025-1 Generator Relay Loadability - SAR Drafting Team.

3.2 Executive Tracking Summary
Gerry Dunbar provided a brief update on the Executive Tracking Summary.

3.3 NERC Project Tracking Spreadsheet
Ruida Shu provided a brief update on the NERC Project Tracking Spreadsheet.

4.0 Open Action Items

4.1 Open Action Items List
Mike Jones indicated the NPCC Regional Feedback Mechanism process document is posted on the NPCC website.

5.0 Items Requiring RSC Discussion

5.1 NERC Weekly Standards Bulletin
Guy Zito provided an update on the NERC Weekly Standards Bulletin.

5.2 Hydro Quebec GMD Studies
Louis Gibson, Luc Gerin-Lajoie and Sebastien Guillon from Hydro Quebec ~~came in and~~ presented the interim resultsof HQ~~their~~ GMD Studies on reproducing the 1989 event~~ in~~ provide an EMTP-RV based ~~E~~estimation of the GMD magnitude. Hydro Quebec has~~ve~~ re-created the 1989 black out event in their simulation ~~(~~Network, sequence of events, sensitivity results and network collapse. The goal is to refine the work based on non-uniform fields and time ~~variant depending~~variation depending on the geographical location.

5.3 RSC Work Plan 2017-2018
Approval of the RSC Work Plan 2017-2018 with no additional edits.
Herb Schrayshuen made a motion for approval.
Mike Jones seconded the motion.

The RSC Work Plan 2017-2018 were approved as documented.

5.4 RSC Scope of Work 2017-2018

Approval of the RSC Scope of Work 2017-2018 with no additional edits.
Herb Schrayshuen made a motion for approval.
Jim Grant seconded the motion.

The RSC Scope of Work 2017-2018 were approved as documented.

5.5 2017 ERO Enterprise Compliance Monitoring and Enforcement Implementation Plan

5.6 CIP Supply Chain CIP-013-1 Presentation

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	12/8/16 Call-In
Project 2016-02 Modifications to CIP Standards	12/5/16 (F)	12/5/16 (A)	Al McMeekin	1.00PM
Enhanced Periodic Review Standing Review Team - Standards Grading	8/1/16 (I)	NA	Mat Bunch	1:15PM
Project 2013-03 Geomagnetic Disturbance Mitigation Revisions to Project White Papers	6/13/16 (I)	NA	Mark Olson	1:20PM
Project 2016-01 Modifications to TOP and IRO Standards	10/17/16 (F)	10/17/16 (A)	Mark Olson	1:35PM
Project 2016-03 Cyber Security Supply Chain Management SAR	11/18/16 (I)		Mark Olson	1:50PM
Project 2015-09 Establish and Communicate System Operating Limits	8/12/16 (I)	NA	Lacey Ourso	2:05PM
Functional Model Advisory Group	9/7/16 (I)	NA	Lacey Ourso	2:20PM
Project 2015-08 Emergency Operations EOP-004-4	1/6/17 (F)	1/6/17 (A)	Laura Anderson	2:30PM
Project 2015-10 Single Points of Failure TPL-001	6/24/16 (I)	SAR	Jordan Mallory	2:45PM
Project 2016-04 Modifications to PRC-025-1	10/18/16 (F)		Jordan Mallory	3:00PM
Revisions to the NERC Standard Processes Manual	10/28/15 (I)	NA	Guy Zito	3:15PM
Comments: (I) – Informal; (F) – Formal; (N) – Nomination Period **Ballots:** (I) – Initial; (A) – Additional; (F) – Final				

Project 2016-02 Modifications to CIP Standards:
Al McMeekin and the rest of the SDT called in at 1PM.
CIP-003-7 package has been completed and ready to be posted ~~for tomorrow~~ December 9, 2016 for final ballot.
Language has been changed from “shall” to “options” in the Guidelines and Technical Basis reference models.

Implementation plan is increased to 18 months.
Transient Cyber Asset (TCA) at low will be posted for an initial comment and ballot period on December 9, 2016.
Low Impact External Routable Connectivity (LERC) and Transient Cyber Asset (TCA) at low will be combined and posted ~~it~~ for January 2017.
RSAW of Transient Cyber Asset (TCA) will be posted for an initial comment and ballot period on December 9, 2016.
Virtualization sub team has put together a risk map which identifies the risks in the virtual system.
Communication network will be posted for an informal comment period to collect industry comments.
Definition and concepts sub team is in a hold position at the moment.

Enhanced Periodic Review Standing Review Team – Standards Grading:
Mat Bunch called in at 1PM.
Final score of the standards are posted on the NERC website.
VAR and PER standards will be reviewed.
There are several standards selected~~picked out~~ for 2017 review.

Project 2013-03 Geomagnetic Disturbance Mitigation Revisions:
Mark Olson called in at 1:20PM.
The Standards Committee will act on making appointments to the SDT.
The SAR is drafted and ~~it is~~has been sent to the Standards Committee for approval.
The SAR is intended to address the FERC Directives.
~~Requirement 5 is added to address "cyber security policies" for low impact BES Cyber Systems.~~
~~It will be an informal posting for the draft SAR.~~

Project 2016-01 Modifications to TOP and IRO Standards:
Very minimal changes were made since the standard passed~~t~~ the additional ballot.
It is currently posted for final ballot.
The ballot will close on Monday December 12, 2016.

Project 2016-03 Cyber Security Supply Chain Management:
The SDT reviewed the SAR comments submitted by the entities.
Significant direction changes after the October 2016 technical conference.
The goal is to post the draft standard in January 2017.
Requirement 5 is added to address the low impact BES Cyber System.
The SDT is working closely with the compliance personnel to develop a better Guidelines and Technical Basis section.
Definition of supply chain has not been discussed by the SDT.
Implementation Guidance is still under review and the target goal is to complete this by January 2017.

Project 2015-09 Establish and Communicate System Operating Limits:
The SDT decided to seek additional support and guidance from subject matter experts.
There will be a joint task force formed for next week to discuss the standard and the next step.

Functional Model Advisory Group:
Howard Gugel provided an update on the ~~Functional Model~~history of the Functional Model and work of the Functional Model Advisory Group.
There were a lot of questions and concerns on the last revision of Function Model, specifically on the registration issues.
The drafting team met in November 2016 and review the comments.
To be determined: Functional Model Advisory Group tasks for the group going forward.

Project 2015-08 Emergency Operations EOP-004-4:
Laura Anderson called in at 2:30PM.
The standard is currently posted for 45-day additional comment period.
The SDT made substantial changes based on the industry comments.
It is also posted for a 10-day ballot period from December 28, 2016 to January 6, 2017.

Project 2015-010 Single Points of Failure TPL-001:
Jordan Mallory called in at 2:33PM.
The SDT addressed table 1 and foot note 13 in the standard.
The SDT will develop an Implementation Guidance Documents and it will be an auditor approved document.
The document will be endorsed by the ERO to help the entities.
Compliance Guidance and Implementation Guidance documents will be vetted by the ERO.
Soo Jin Kim will take over this Project going forward.

Project 2016-04 Modifications to PRC-025-1:
The SDT received 14 comments on the SAR posting.
Most of the comments are supportive of the Project.
The plan is to go out for additional drafting team members.

6.2 Ballot History (Since last RSC Meeting)
Ruida Shu reviewed the Ballot History document in the meeting.

6.3 Comment Form History (Since last RSC Meeting)
Ruida Shu reviewed the Comment Form History document in the meeting.
Action Item: Ruida Shu and Guy Zito will review and propose a few methods to display comment responses from NERC on all of the RSC comments.

7.0 NERC Drafting Team Nominations

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 FERC Approved the Retirement of PRC-002-NPCC-01

8.1.2 Automatic Underfrequency Load Shedding PRC-006-NPCC-02 status update

Ruida Shu provided a brief update on the status of PRC-006-NPCC-02.

8.1.3 PRC-006-3 Automatic Underfrequency Load Shedding Quebec Variance status update

Ruida Shu indicated the second comment period on PRC-006-3 Automatic Underfrequency Load Shedding Quebec Variance will end on December 14, 2016. The plan is to put this out for a 30-day pre-ballot period following a 10-day ballot period in January 2017.

8.1.4 Geomagnetic Disturbance Mitigation TPL-007-1 Quebec Variance

Si Truc Phan indicated the work is still under development.

9.0 NPCC Non-Standards

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

9.1 Directories:

9.1.1 Directory#8 *System Restoration* – (status of CO11 review).

-The Task Force on Coordination of Operation (TFCO) and its CO-11 Restoration Working Group completed a comprehensive review of the document in early 2016 and posted a draft to the Open Process which contained the following revisions:

- Eliminated duplicative or conflicting battery testing requirements with the recently approved PRC-005-2.
- An overall reformatting of the criteria into NERC style requirements consistent with the goals of the NPCC Directory project.
- Revisions to the definitions of three NPCC defined Glossary terms.
- The development of a new Appendix (Appendix D) which provides a comparison table between revised Directory#8 test procedures and the equivalent tests in previous versions of the document.

-TFCO is currently preparing a third 45 day posting of Directory#8 as a result of further clarifying changes made to the document after comment review.

9.1.2 Directory#9 and #10 *Real and Reactive Capability Verification* - (status of TFCO review).

-TFCO and its CO7 Working Group have recommended that Directories #9 and #10 can be retired pending the completion of the staged implementation of MOD-25-2 in July 2019.

-TFCO posted the retirement recommendation to the Open Process and is currently reviewing comments.

9.1.3 Directory#7 *SPS* and NPCC Glossary term SPS – (status of PRC-12-2)

PRC-012-2 *Remedial Action Schemes* is currently filed with the commission. TFSP will defer is review of the Directory#7 criteria pending the outcome of the PRC-012-2.

9.1.4 A-10 *Classification of BPS Elements* (status of TFCP review).
-Currently a draft action plan developed by the TFCP has been sent to each of the NPCC Task Forces for review and comment.
-Once the Task Force comments have been considered the action plan will assigned to the CP11 and serve as a guide for the review.
-The CP11 review is anticipated to commence in early 2017.

9.1.5 A-01 *Criteria for Review and Approval of Documents* – (status of TFCP review).
-TFCP has posted an updated version of the document to the Open Process for a second 45-day comment period.
-TFCP has proposed an expedited comment period of no less than 30 days for NPCC 'C' Procedure documents when the lead Task Force anticipates implementation issues.
-RSC to consider incorporating A-01 into the Directory Review and Revision Manual
-Once the language of the A-01 has been finalized RSC to consider incorporating the A-01 into the Directory Revision and Review Manual.

9.1.6 Directory#2 *Emergency Operations* and Directory#5 *Reserve* - (status of TFCO review).
-TFCO has assigned its Working Groups the CO-1 Working Group on Control Performance (Directory#5---Reserve) and the CO-8 Working Group on System Operations Managers (Directory#2---Emergency Operations) to begin a review of a draft of each Directory.
-The respective drafts contain the existing criteria reformatted into NERC style requirements. The goal of the Working Group review will be to ensure that the draft with reformatted criteria captures the spirit and purpose of the criteria as currently contained in the existing Member approved documents. The Working Groups have been instructed to avoid revising the criteria and to return any disagreements over interpretation to the TFCO.
-Once TFCO has approved the Working Groups review of the reformatted criteria the Directories will be posted to the Open Process for Member comment. The posting date will be contingent on the progress of the Working Groups review.

9.1.7 Criteria Clarifications;
-Directory#4 *System Protection Criteria* (Pending Request for Clarification—TFSP)
-The TFSP rendered a response to the Request for Criteria Clarification as submitted by Eversource Energy. The TFSP Clarification was posted to the Open Process and the TFSP responded to all comments (none were

received). In accordance with the NPCC Directory Development and Review Manual the TFSP Clarification was approved by the RCC on December 6th, 2016 and will be archived on the NPCC website.

9.2 RAS Implementation/Transition
-Effective date of the revised definition of RAS is 4-1-2017.
-The TFCP has requested the TFSS to review the current SPS list and identify 1) SPS's that conform to the definition 2) SPS's that do not conform to the definition 3) newly identified RAS's that have not been subject to a regional review since they were not previously identified as an SPS.
-TFSS is incorporating the TFCP request with its annual update of the SPS list and anticipates completing the TFCP request in January 2017.
-The RC Members of the TFCP participated in a conference call and indicated their desire to continue to participate in the regional review process for an SPS after PRC-012-2 is effective.
-TFCP and NPCC staff developed options which will serve as guidance for the transition including the disposition of the existing Glossary term - Special Protection System (SPS).

10.0 <u>RSC Member Items of Interest</u>

10.1 RSC Roster

11.0 <u>Standards Activity Post NERC BOT Approval</u>
(Since last RSC Meeting)

11.1 NERC Filings to FERC
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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	March 9th - Meeting	April 20th - Call
June 15th - Meeting	July 20th - Call	September 14th Meeting
October 19th - Call	December 14th - 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

Corrected link:
http://www.nerc.com/comm/RISC/Related%20Files%20DL/ERO_Reliability_Risk_Priorities_RISC_Reccommendations_Board_Approved_Nov_2016.pdf

13.0 NERC Items of Interest (Since last RSC Meeting)

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

13.1.1 There have been three new Lesson Learned issued since the last RSC meeting.

13.2 Alerts

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

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

13.3 Second Draft of 2017 Business Plan and Budget

13.4 Standard Committee 2017 Meeting Schedule

January 18th - Call	March 15th - WECC	April 19th – Call
June 14th – Atlanta	July 18th – Call	September 7th – MRO
October 18th – Call	December 6th - Atlanta	

13.5 Notice of Proposed Revisions to NERC Rules of Procedure

14.0 Other Items of Interest

14.1 NPCC Compliance Committee (CC) Schedule

January 13th – Call	February 17th – Call	March 15-16th Meeting
April 13th – Call	May 10-12th Workshop	June 21-2nd Meeting
July 13th – Call	August 17th – Call	September 20-21st Meeting
October 12th – Call	November 15-17th Workshop	December 8-9th Meeting

14.2 NPCC Board of Directors Meeting (BOD) 2016

February 2nd – Control Center Tour February 3rd - IESO Offices	March 23rd – Call	April 27th – NPCC Offices
June 2nd – Call	June 29th – NPCC Offices	August 3rd - Call
September 7th – NPCC Long Range Strategy Session September 8th – NPCC Offices	October 25th – Call	December 7th – Montreal, Quebec

14.3 NPCC Board of Directors Meeting (BOD) 2017

February 1st - FRCC Office, Tampa, FL	March 22nd - Call	May 3rd – NPCC Office
June 1st – Call	June 28th – NPCC Office	August 2nd – Call
September 6th and 7th – Portland ME	November 1st – Call	December 6th – Boston MA

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2016 Meeting Dates

February 17th-18th, NextEra Energy Offices, Juno Beach FL
April 19th & 20th, NPCC Offices, New York NY
June 22nd & 23rd, Saratoga NY
August 10th & 11th, Toronto Canada
October 5th & 6th, Lewiston NY
December 8th & 9th, Montreal Canada

RSC 2017 Meeting Dates

March 8th-9th, FRCC, Tampa FL
June 7th-8th, Saratoga NY
August 23rd-24th, Toronto/Montreal
October 11th-12th, Lewiston NY
December 7th, General Meeting

15.2 RSC 2016 Conference Call Schedule (calls can be schedule as needed) all Calls are planned to start at 10:00 a.m. (call: 415-655-0003 (USA) / 416-915-6530 (Canada), Guest Code 28840965)

January 8	January 22	February 5
March 4	March 18	April 1
April 29	May 13	May 27
June 10	July 8	July 22
August 5	September 2	September 16
September 30	October 21	November 4
November 18	December 23	

The meeting is adjourned at 9.53AM on December 9, 2016.

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**
2007-17.4	PRC-005 FERC Order No. 803 Directive	Standard				
2009-02	Real-time Monitoring and Analysis Capabilities	Standard	T.J. (Tim) Kucey	PSEG Fossil, LLC		Timothy.Kucey@pseg.com
2009-03	Emergency Operations	Standard	Connie Lowe	Dominion Resource Services, Inc.	804-819-2917	connie.lowe@dom.com
2010-05.2	Remedial Action Schemes (Phase 3 of Protection Systems)	Standard	Charles-Eric Langlois	Hydro-Quebec TransEnergie	514-879-4100	langlois.charles-eric@hydro.qc.ca
2010-14.1	Balancing Authority Reliability-Based Control, Phase 1: Reserves	Standard				
2010-14.2	Balancing Authority Reliability-Based Control, Phase 2	Standard				
2010-14.2.2	Periodic Review of BAL Standards - BAL-004	Standard				
2013-03	Geomagnetic Disturbance Mitigation	Standard	Per-Anders Lof	National Grid	781-907-5581	per-anders.lof@nationalgrid.com
2014-01	Standards Applicability for Dispersed Generation Resources	Standard	Brian Evans-Mongeon	Utility Services	802-552-4022	brian.evans-mongeon@utilitysvcs.com
2015-03	Periodic Review of System Operating Limit Standards	Standard	Dean Laforest Sam Jager	ISO-NE IESO		
2015-04	Alignment of NERC Glossary of Terms and Definitions Used in the Rules of Procedure (Appendix 2 of the Rules of Procedure)	Standard	Jill Loewer	Utility Services		jill.loewer@utilitysvcs.com
2015-08	Emergency Operations - EOP-004, EOP-005, EOP-006, EOP-008	Standard	Connie Lowe Karen Backmen	Dominion IESO	804-819-2917	connie.lowe@dom.com Karen.backmen@ieso.ca
2015-09	Establish and Communicate System Operating Limits - FAC-010, FAC-011, FAC-014	Standard	Dean Laforest Sam Jager	ISO-NE IESO		
2015-10	Single Points of Failure - TPL-001	Standard	Ovidiu Vasilachi Rich Kowalski	IESO Observer ISO-NE		
2016-01	Modifications to TOP and IRO Standards - TOP-001, IRO-002	Standard	Steve Brain Philippe Labrosse	Dominion Resource Services, Inc. Hydro-Quebec TransEnergie		
2016-03	Cyber Security Supply Chain Management	Standard	Norm Dang David Bryan Gayle	IESO Dominion Resource Services, Inc.		
2016-04	Modifications to PRC-025-1	Standard				

Source = NERC Standard Drafting Team Rosters - September 2016

Projects Added:

1. Project 2015-06 Interconnection Reliability Operations and Coordination - IRO-006-East and IRO-009
2. Project 2015-07 Internal Communications Capabilities - COM-001
3. Project 2015-08 Emergency Operations - EOP-004, EOP-005, EOP-006, EOP-008

NPCC Representatives on NERC Standards Drafting Teams

Project No.	Project Title	DT Type	NPCC Representatives	Company	Telephone	E-mail Address
2007-06	Phase 1: System Protection Coordination	Standard	None			
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
2007-17.4	PRC-005 FERC Order No. 803 Directive	Standard				
2008-02	Undervoltage Load Shedding	Standard	Charles-Eric Langlois	Hydro-Quebec TransEnergie	514-879-4100	langlois.charles-eric@hydro.qc.ca
2009-02	Real-time Monitoring and Analysis Capabilities	Standard	T.J. (Tim) Kucey	PSEG Fossil, LLC		Timothy.Kucey@pseg.com
2009-03	Emergency Operations	Standard	Connie Lowe	Dominion Resource Services, Inc.	804-819-2917	connie.lowe@dom.com
2010-03	Modeling Data (MOD B)	Standard				
2010-05.1	Protection Systems: Phase 1 (Misoperations)	Standard	Paul Difilippo	Hydro One Networks	647-328-7068	paul.difilippo@hydroone.com
2010-05.2	Remedial Action Schemes (Phase 3 of Protection Systems)	Standard	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				
2010-14.2	Balancing Authority Reliability-Based Control, Phase 2	Standard			-	
2010-14.2.2	Periodic Review of BAL Standards - BAL-004	Standard				
2012-09	IRO Five-Year Review	Standard	John Mulhern	Con Edison	212-580 6791	mulhernj@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	802-241-1400	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	Standard	Jill Loewer	Utility Services	802-241-1400	jill.loewer@utilitysvcs.com
2015-06	Interconnection Reliability Operations and Coordination - IRO-006-I	Standard				
2015-07	Internal Communications Capabilities - COM-001	Standard				
2015-08	Emergency Operations - EOP-004, EOP-005, EOP-006, EOP-008	Standard	Connie Lowe Karen Backman	Dominion IESO	804-819-2917	Connie.lowe@dom.com

Source = NERC Standard Drafting Team Rosters - June 2015

Projects Added:

1. Project 2015-06 Interconnection Reliability Operations and Coordination - IRO-006-East and IRO-009
2. Project 2015-07 Internal Communications Capabilities - COM-001
3. Project 2015-08 Emergency Operations - EOP-004, EOP-005, EOP-006, EOP-008

NPCC Document Open Process Executive Tracking Summary

Revised: 1/24/2017 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	TFCP Review Underway.	TFCP considering comments received during 2nd Posting which concluded on Jan. 6, 2017.
2	Criteria	A-10	Classification of BPS Elements	Dec-09	TFCP to Review in 2017.	TFCP Developing Scope of Review---CP11 Review to Begin Early 2017.
3	Criteria	A-15	Disturbance Monitoring Equipment Criteria	Aug-07	A-15 Retired October 2016.	A-15 Retired October 2016 (Directory#11 Approved).
4	Guideline	B-01	NPCC Guide for the Application of Autoreclosing to the Bulk Power System	Feb-13	TFSP Updated in January 2017	Open Process Posting Pending.
5	Guideline	B-25	Guide to Time Synchronization Substation Equipment	Nov-08	B-25 Retired October 2016.	Incorporated into Draft Directory#11 (Appendix A)
6	Guideline	B-26	Guide for Application of Disturbance Recording Equipement	Sep-06	B-26 Retired October 2016.	Incorporated into Draft Directory#11 (Appendix B)
7	Guideline	B-27	Regional Critical Asset Identification Methodology	Feb-08	TFIST Retirement Recommendation.	B-27 Retired 6/01/2016.
8	Guideline	B-28	Guide for Generator Sequence of Events Monitoring	Feb-12	B-27 Retired October 2016.	Incorporated into Draft Directory#11 (Appendix C)
9	Procedure	C-01	NPCC Emergency Preparedness Conference Call Procedures - NPCC Security Conference Call Procedures	Jun-16	Revised.	TFCO Completed Update June 2016.
10	Procedure	C-15	Procedures for Solar Magnetic Disturbances Which Affect Electric Power Systems	Jun-16	Revised.	TFCO Completed Update June 2016.
11	Procedure	C-25	Procedure to Collect Power System Event Data	Sep-07		TFSS to Review and Update for Inclusion in D#11 as Appendix or Recommend Retirement.
12	Procedure	C-29	Procedures for System Modeling:Data Requirements and Facility Ratings	Mar-07	Retired. (MOD-032-1).	TFSS Approved Retirement January 2017.
13	Procedure	C-30	Procedure for Task Force on System Protection Review of Disturbances and Protection Misoperations	Dec-09	Retired.	TFSP Retired C-30 June 2016.
14	Procedure	C-33	Procedure for Analysis and Classification of Dynamic Control Systems	Apr-06		Pending TFSS review.
16	Procedure	C-35	NPCC Power System Restoration Guideline	Mar-16	Retired.	TFCO/CO11 established C-35 as a Reference Document.
16	Procedure	C-39	Procedure to Collect Major Disturbance Event Data	Dec-09	Retired	TFSP retired C-39 June 2016.
17	Procedure	C-43	NPCC Operational Review for the Integration of New facilities	Aug-08		Pending TFCO review.
18	Procedure	C-45	Procedure for Analysis and Reporting of Protection System Misoperations	Jul-16	Revised.	TFSP revised C-45 July, 2016.

NPCC Directory Executive Tracking Summary

Revised: **1/25/2017** Further details regarding the individual documents may be found at:

	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	Oct-15		
2	Directory #2	Criteria A-3	Emergency Operations	TFCO	Jun-09		TFCO Working Group CO-8 considering recommendations/redlines from CO8 Members prior to beginning formal review.
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 the enforcement date of PRC -005-2.	
4	Directory #4	Criteria A-5	Bulk Power System Protection Criteria	TFSP	Oct-15		
5	Directory #5	Criteria A-6	Reserve	TFCO	Oct-12		TFCO Working Group CO1 currently reviewing an intial draft of D#5 with reformatted NERC style requirements.
6	Directory #6		Regional Reserve Sharing		Apr-12		
7	Directory #7	Criteria A-11	Special Protection Systems	TFSP	Jul-13		Pending approval of PRC-012-2 TFSP to consider review of Directory#7 criteria and NPCC Glossary definition of SPS.
8	Directory #8	Criteria A-12	System Restoration	TFCO	Oct-10		Subsequent to PRC-005-2 approval TFCO has revised battery testing criteria. D#8 Posted to the Open Process for a 3rd Posting through Feb. 6, 2017.
9	Directory #9	Criteria A-13	Verification of Generator Gross and Net Real Power Capability	TFCO	Dec-11		TFCO posted recommendation to retire D#9 and D#10 pending full enforcement of MOD-25-2. (July 2019). TFCO currently considering comments.
10	Directory #10	Criteria A-14	Verification of Generator Gross and Net Reactive Power Capability	TFCO	Dec-11		See D#9.
11	Directory#11	Criteria A-15	Disturbance Monitoring	TFSP	Oct-16	D#11 Approved October 2016.	
12	Directory#12		UFLS	TFSS	Oct-12		

NPCC Directory Criteria Clarifications

Revised: **1/25/2017** 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	Yes	Interpretation on behalf of IESO-MACD	Complete.
7	Directory#8 Clarification	System Restoration	12/1/2015	TFCO	Yes	Yes	Clarification on Behalf of OPG.	Complete.
8	Directory#5 Clarification	Reserve	9/7/2016	TFCO	Yes	Yes	Clarification on Behalf of the NYISO.	Complete

x

1/25/2017

Filing Period	Filing Due	Filing Submitted	Comments
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.
January 1 to March 31, 2013	6/1/2013	N/A	No changes were made during the refeenced period which required filing.
April 1 to June 30, 2013	9/1/2013	N/A	No changes were made during the referenced period which required filing.
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.
October 1 to December 31, 2013	3/1/2014	N/A	No changes were made during the referenced period which required filing.
January 1 to March 31, 2014	6/1/2014	N/A	No changes were made during the referenced period which required filing.
April 1 to June 30, 2014	9/1/2014	N/A	No changes were made during the referenced period which required filing.
July 1 to September 30, 2014	12/1/2014	N/A	No changes were made during the referenced period which required filing.
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.
	3/1/2015	N/A	(2) 10/6/14 the RSC approved revisions to the Directory Manual which incorporated cost considerations into the Manual.
January 1st to March 31st 2015	6/1/2015	N/A	No changes were made during the referenced period which required filing.
April 1st to June 30th 2015	9/1/2015	N/A	No changes were made during the referenced period which required filing.

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SUMMARY
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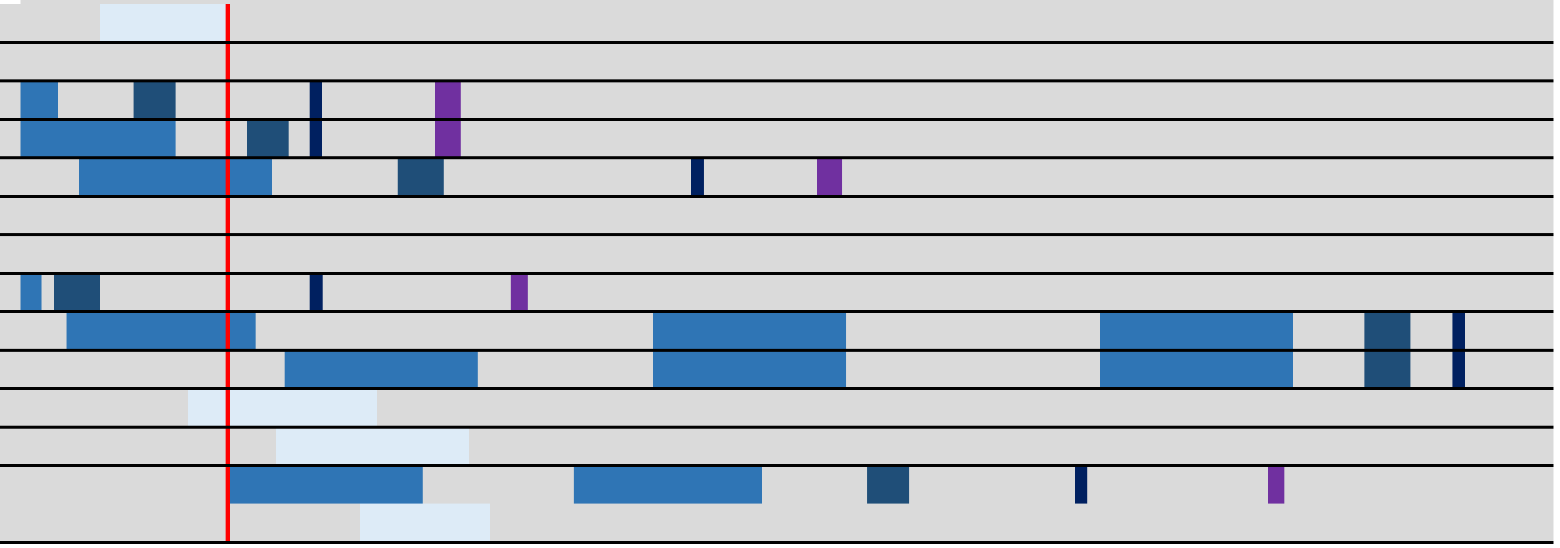
HOME

Project (Filter)	Deliverables (Filter)	Early/(Late) Days (Filter)	Baseline/ Current (Filter)
2013-03 - Geomagnetic Disturbance Mitigatior	TPL-007-2		Proposed
2015-04 - Alignment of Terms	Report on process (Phase II Im		Proposed
2015-08 - Emergency Operations	EOP-005, EOP-006, and EOP-0(	(205)	Current
2015-08 - Emergency Operations	EOP-004	(155)	Current
2015-09 - Establish and Communicate System	FAC-010-3, FAC-011-3, and FA(	(58)	Current
2015-10 - Single Points of Failure TPL-001	TPL-001		Current
2015-INT-01 - Interpretation of CIP-002-5.1 for	Interpretation CIP-002-5.1	(9)	Current
2016-02 - Modifications to CIP Standards	LERC Definition	27	Current
2016-02 - Modifications to CIP Standards	Directives, Control Center Com		Current
2016-02 - Modifications to CIP Standards	V5TAG issues: Cyber Asset and		Current
2016-EPR-01 - Enhanced Periodic Review of Pe	PER-003-1 and PER-004-2		Current
2016-EPR-02 - Enhanced Periodic Review of Vc	VAR-001-4.1 & VAR-002-4		Current
2016-03 - Cyber Security Supply Chain Manage	New and revised Standard(s)		Proposed
2016-04 - Modifications to PRC-025-1	PRC-025-2		Proposed

2016 Dec | 2017 Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov



Project Name	Status	Comments	Deliverable	Deadline	Priority in 2016-2018 RSDP, if applicable (see Note 1)	P81 Req (2013)	Number of Directives	No. of Guidances (see Note 2)	Directionally consistent with IERP findings (See Note 5)	Developer	PMOS Liaison	Affected Standards	Last Updated
(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	HOME
Phase 2 of Balancing Authority Reliability-based Controls - BAL-004-2	Pending Regulatory Approval	Filed with regulators on November 10, 2016.	BAL-004	N/A	N/A	N/A	N/A	4	N/A	Darrel Richardson	Ken Goldsmith	BAL-004	12/13/2016
Geomagnetic Disturbance Mitigation	Nominations & SAR	FERC issued Order No. 830 on September 22, 2016 approving TPL-007-1 and directing modifications. The SDT will develop revised or new requirements to enhance the benchmark GMD event used in GMD assessments, require collection of GMD data, and establish deadlines for GMD Corrective Action Plans and mitigation measures. Revisions must be filed by May 29, 2018. Projected: Additonal SDT member appointments Dec 14; SAR acceptance in March 2017.	TPL-007-2	43249	N/A	N/A	N/A	N/A	N/A	Mark Olson	Jennifer Sterling	TPL-007-1	1/4/2017
Alignment of Terms	Other	SDT is developing recommendations to present to SC. The Phase II work was completed in February 2016 and the proposed recommendations were submitted for consideration at the March 2016 meeting. The item was pulled from the SC agenda based on a request from the SC chair, Brian Murphy. The SDT reviewed the revisions proposed by the SC chair, and determined to move forward with submitting the recommendations as developed by the SDT. The Phase II recommendation document will be resubmitted for inclusion on the September 2016 SC agenda.	Report on process (Phase II Improvement Report)	N/A	N/A	N/A	N/A	N/A	N/A	Lacey Ourso	Andrew Gallo	Glossary/ROP	10/4/2016
Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec)	Pending Regulatory Approval	Interpretation passed. FERC Approved, RD docket.	Interpretation CIP-002-5.1	N/A	N/A	N/A	N/A	N/A	N/A	Al McMeekin	Brian Murphy and Andrew Gallo	CIP-002-5.1	1/4/2017
Modifications to TOP and IRO Standards	Posted	Preparing for final ballot in Dec 2016. NOPR issued June 18, 2015 (under previous project 2014-03). Final Rule issued November 19, 2015 with three directives with an associated 18 month regulatory filing deadline. The SC authorized posting at the June 2016 SC meeting. Standards passed additional ballot ending October 17 2016 and will be posted for final ballot early December 2016.	TOP/IRO Standards	FERC deadline of July 27, 2017	N/A	N/A	N/A	N/A	N/A	Mark Olson	Rod Kinard	TOP/IRO Standards	12/13/2016
Cyber Security Supply Chain Management	Working to Comment Posting	SDT is reviewing SAR comments and developing draft standard. The project will address directives from Federal Energy Regulatory Commission (FERC) Order No. 829 to develop a new or modified standard to address "supply chain risk management for industrial control system hardware, software, and computing and networking services associated with bulk electric system operations." See Order No. 829, at P1. Projected initial posting Jan 19 - March 6, 2017. "Planned (internal)" 2nd posting (T) April 12 - May 26, 2017.	New and revised Standard(s)	43005	N/A	N/A	1	N/A	N/A	Mark Olson	Brenda Hampton, Rod Kinard, and Angela Kimmey	New and revised Standard(s)	1/4/2017

Modifications to PRC-025-1	SAR	The Standards Authorization Request (SAR) to modify PRC-025-1 was posted for a 30-day formal comment period on September 16, 2016 along with a solicitation for SAR drafting team (DT) members. NERC received too few nominations initially. A second nomination period was posted from December 6-19, 2017. NERC will present vetted and recommended SAR DT candidates for appointments during the January 18, 2017 Standards Committee (SC) conference call. The SAR DT meetings are anticipated to be 2-3 conference calls due to the few comments received in the SAR posting period. Tentatively, calls would occur after the SC January meeting and the first week February 2017.	New and revised Standard(s)	None, enhancemens to 025 affects entities currently implementing version 1 under the five and seven year implementation period. The first period ends October 1, 2019 and the second on October 1, 2021. Project must consider the time for development and subsequent	N/A	N/A	N/A	N/A	Yes	Scott Barfield-McGinnis	Charles Yeung	PRC-025-1	1/4/2017
Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards	Posted	Templates are posted for a 45-day formal comment period.	PER-003-1 and PER-004-2	N/A	N/A	N/A	N/A	N/A	N/A	Darrel Richardson	Mike Brytowski	PER-003-1 and PER-004-2, but PER-001-0.2 was not evaluated due to retirement on April 17, 2017.	1/10/2017
Enhanced Periodic Review of Voltage and Reactive Standards	Working to Comment Posting	The team completed their review of the two VAR standards and completed each of the EPR templates during their January 3, 2017 conference call. The team will meet with the SRT the week of January 23, 2017 to affirm recommendations before posting for a 30-day informal comment period	VAR-001-4.1 & VAR-002-4	N/A	N/A	N/A	N/A	N/A	N/A	Scott Barfield-McGinnis	Amy Casuscelli	VAR-001-4.1 & VAR-002-4	1/4/2017

Project	**2013-03**	**Home**
Project Name	Geomagnetic Disturbance Mitigation	
Status	Nominations & SAR	
Comments	FERC issued Order No. 830 on September 22, 2016 approving TPL-007-1 and directing modifications. The SDT will develop revised or new requirements to enhance the benchmark GMD event used in GMD assessments, require collection of GMD data, and establish deadlines for GMD Corrective Action Plans and mitigation measures. Revisions must be filed by May 29, 2018. Projected: Additonal SDT member appointments Dec 14; SAR acceptance in March 2017.	
Deliverable	TPL-007-2	
Deadline	May 29, 2018	
Priority in 2016-2018 RSDP, if applicable (see Note 1)	N/A	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Mark Olson	
PMOS Liaison	Jennifer Sterling	
Affected Standards	TPL-007-1	
Last Updated	1/4/2017	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR	10/20/2016	11/9/2016	10/20/2016	11/9/2016			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	12/20/2016	1/19/2017	12/20/2016	1/19/2017			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							

CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
No dates provided	6/1/2016	Project finished prior to 2015.

Project	**2015-04**	**Home**
Project Name	Alignment of Terms	
Status	Other	
Comments	SDT is developing recommendations to present to SC. The Phase II work was completed in February 2016 and the proposed recommendations were submitted for consideration at the March 2016 meeting. The item was pulled from the SC agenda based on a request from the SC chair, Brian Murphy. The SDT reviewed the revisions proposed by the SC chair, and determined to move forward with submitting the recommendations as developed by the SDT. The Phase II recommendation document will be resubmitted for inclusion on the September 2016 SC agenda.	
Deliverable	Report on process (Phase II Improvement Report)	
Deadline	N/A	
Priority in 2016-2018 RSDP, if applicable (see Note 1)	N/A	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Lacey Ourso	
PMOS Liaison	Andrew Gallo	
Affected Standards	Glossary/ROP	
Last Updated	10/4/2016	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							

CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes

Project	**2015-08**	**Home**
Project Name	Emergency Operations	
Status	Posted	
Comments	Posted for final ballot.	
Deliverable	EOP-005, EOP-006, and EOP-008	
Deadline	N/A	
Priority in 2016-2018 RSDP, if applicable (see Note 1)	Medium	
P81 Req (2013)	N/A	
Number of Directives	1	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Laura Anderson	
PMOS Liaison	Ken Goldsmith	
Affected Standards	EOP-005, EOP-006, and EOP-008	
Last Updated	1/4/2017	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT							
QR - Quality Review	6/14/2016	6/27/2016	1/11/2016	1/21/2016	(155)		
SP1 - SAR/PR/WP Posting 1	7/21/2015	8/19/2015	7/15/2015	8/14/2015	(6)		
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	6/29/2016	8/12/2016	1/25/2016	3/10/2016	(156)		
CAB - Com/Add Ballot 2	10/26/2016	12/9/2016	4/4/2016	5/19/2016	(205)		
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							

FB - Final Ballot	12/28/2016	1/6/2017	6/6/2016	6/16/2016	(205)		
PTB - Present to BOT	2/8/2017	2/10/2017	8/8/2016	8/10/2016	(184)		
Filing - Filing with Regulators	3/10/2017	3/15/2017	9/7/2016	9/12/2016	(184)		
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Explain delay	6/6/2016	The SDT slowed development.

Project	**2015-08**	**Home**
Project Name	Emergency Operations	
Status	Posted	
Comments	Draft 2 is currently posted for a 45-day comment period and 10-day ballot.	
Deliverable	EOP-004	
Deadline	N/A	
Priority in 2016-2018 RSDP, if applicable (see Note 1)	Medium	
P81 Req (2013)	N/A	
Number of Directives	1	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Laura Anderson	
PMOS Liaison	Ken Goldsmith	
Affected Standards	EOP-004	
Last Updated	1/4/2017	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT							
QR - Quality Review	7/14/2016	7/28/2016	4/8/2016	4/18/2016	(97)		
SP1 - SAR/PR/WP Posting 1	7/21/2015	8/19/2015	7/15/2015	8/14/2015	(6)		
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	7/25/2016	9/8/2016	4/18/2016	6/2/2016	(98)		
CAB - Com/Add Ballot 2	11/18/2016	1/6/2017	6/27/2016	8/11/2016	(144)		
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							

FB - Final Ballot	1/24/2017	2/2/2017	8/22/2016	9/1/2016	(155)		
PTB - Present to BOT	2/8/2017	2/10/2017	10/31/2016	11/2/2016	(100)		
Filing - Filing with Regulators	3/10/2017	3/15/2017	11/30/2016	12/5/2016	(100)		
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Explain delay in project	5/1/2016	The delay was to reduce industry burden by simplifying the event reporting process such that a single form and submission system satisfies both EOP-004 and the U.S. Department of Energy's reporting requirements, the Project 2015-08 EOP SDT is collaborating with the U.S. Department of Energy to harmonize reporting requirements/reports. This collaboration has changed the project schedule for EOP-004. The project's PMOS representative, Ken Goldsmith, supports this project timeline change.

Project	**2015-09**	**Home**
Project Name	Establish and Communicate System Operating Limits	
Status	Working to Initial Ballot	
Comments	The drafting team will be meeting in Phoenix, AZ February 21-24, 2017	
Deliverable	FAC-010-3, FAC-011-3, and FAC-014-2	
Deadline	N/A	
Priority in 2016-2018 RSDP, if applicable (see Note 1)	Medium	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Darrel Richardson	
PMOS Liaison	Andrew Gallo	
Affected Standards	FAC-010-3, FAC-011-3, and FAC-014-2	
Last Updated	1/19/2017	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT							
QR - Quality Review			4/4/2016	4/14/2016		Not needed	
SP1 - SAR/PR/WP Posting 1	8/20/2015	9/21/2015	8/20/2015	9/21/2015			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	7/8/2016	8/7/2016	7/8/2016	8/7/2016			
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	9/15/2016	10/30/2016	4/18/2016	6/2/2016	(150)		
CAB - Com/Add Ballot 2	12/15/2016	1/29/2017	7/18/2016	9/1/2016	(150)		
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							

FB - Final Ballot	***3/1/2017***	***3/11/2017***	1/2/2017	1/12/2017	(58)		
PTB - Present to BOT	5/10/2017	5/12/2017	2/1/2017	2/3/2017	(98)		
Filing - Filing with Regulators	6/9/2017	6/14/2017	3/3/2017	3/8/2017	(98)		
PT - Post Approval Training							

PTS Change Control

Reason for Update	**Date**	**Notes**
Explain delay	5/1/2016	The apparent delay in the project is due to missing an earlier update to the PMOS Annual Project Calendar. Baseline Schedule has not been adjusted.
Developer change	1/13/2017	Transition from Lacey Ourso to Darrel Richardson.

Project	**2015-10**	**Home**
Project Name	Single Points of Failure TPL-001	
Status	Working to Initial Ballot	
Comments	The TPL SDT meet December 6-8, 2016 in Atlanta GA. The group made it through the 754 SAMS and SPCS report and update the MOD references. FERC Order 786 still needs to be discussed among the group and that will be completed during the SDT meeting the week of February 20, 2017. The goal will be to seek approval to post by the SC at its April 2017 meeting for a 45-day comment and ballot period.	
Deliverable	TPL-001	
Deadline	N/A	
Priority in 2016-2018 RSDP, if applicable (see Note 1)	High	
P81 Req (2013)	N/A	
Number of Directives	2 directives at P40 & P89 (Click this link for FERC Order)	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Soo Jin Kim	
PMOS Liaison	Mark Pratt	
Affected Standards	TPL-001	
Last Updated	1/12/2017	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR	11/12/2015	12/1/2015	1/18/2016	2/1/2016	67		
Nominations - DT	7/22/2016	8/5/2016	7/25/2016	8/8/2016	3		
QR - Quality Review			5/30/2016	6/9/2016			
SP1 - SAR/PR/WP Posting 1	11/12/2015	12/17/2015	11/12/2015	12/17/2015			
SP2 - SAR/PR/WP Posting 2	5/26/2016	6/24/2016	6/15/2016	7/15/2016	20	Expanded Scope	
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							

CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Expansion of Scope	6/14/2016	FERC directives added (P40 & P89) additional scoping in addition to industry comments following the second SAR posting. The MOD references are being updated due to some retiring
Developer change	1/13/2017	Transition from Lacey Ourso to Soo Jin Kim until a new developer is assigned.

Project	**2015-INT-01**	**Home**
Project Name	Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec)	
Status	Pending Regulatory Approval	
Comments	Interpretation passed. FERC Approved, RD docket.	
Deliverable	Interpretation CIP-002-5.1	
Deadline	N/A	
Priority in 2016-2018 RSDP, if applicable (see Note 1)	N/A	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Al McMeekin	
PMOS Liaison	Brian Murphy and Andrew Gallo	
Affected Standards	CIP-002-5.1	
Last Updated	1/4/2017	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT			4/15/2016	4/29/2016			
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	7/27/2016	9/12/2016	7/25/2016	9/8/2016	(2)		
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							

CAB - Com/Add Ballot 5							
FB - Final Ballot	10/13/2016	10/24/2016	10/4/2016	10/14/2016	(9)		91.31%
PTB - Present to BOT	11/15/2016	11/17/2016	11/15/2016	11/17/2016			
Filing - Filing with Regulators	11/28/2016	11/28/2016	12/28/2016	12/31/2016	30		
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Transfer RFI to the CIP SDT and update the SC	6/14/2016	Schedule updated to CIP SDT timeline.
Add CIP Schedule for approval	7/20/2016	Update SC that schedule was approved by SDT, SDT leadership, developer, and PMOS Liaison.
Archive Project	1/18/2017	Standard was filed on 11/28/2016 and may come off active monitoring by PMOS

Project	**2016-02**	**Home**
Project Name	Modifications to CIP Standards	
Status	Pending Board Adoption	
Comments	Standard passed final ballot. Next steps - present to the NERC BOT in February 2017.	
Deliverable	LERC Definition	
Deadline	Directive: March 31, 2017 (LERC only) (March 31 in SAR)	
Priority in 2016-2018 RSDP, if applicable (see Note 1)	High	
P81 Req (2013)	N/A	
Number of Directives	1	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Al McMeekin	
PMOS Liaison	Brian Murphy and Andrew Gallo	
Affected Standards	CIP-003-7	
Last Updated	1/4/2017	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT	3/10/2016	3/24/2016	3/10/2016	3/24/2016			
QR - Quality Review	6/30/2016	7/6/2016	6/30/2016	7/7/2016			
SP1 - SAR/PR/WP Posting 1	3/23/2016	4/21/2016	3/23/2016	4/21/2016			
SP2 - SAR/PR/WP Posting 2	6/1/2016	6/30/2016	6/1/2016	7/1/2016		Expanded Scope	
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	7/21/2016	9/6/2016	7/25/2016	9/8/2016	4		
CAB - Com/Add Ballot 2	10/21/2016	12/5/2016	10/17/2016	12/1/2016	(4)		
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							

FB - Final Ballot	12/9/2016	12/19/2016	1/5/2017	1/15/2017	27		87.95%
PTB - Present to BOT	2/8/2017	2/10/2017	2/8/2017	2/10/2017			
Filing - Filing with Regulators	3/28/2017	3/31/2017	3/28/2017	3/31/2017			
PT - Post Approval Training							

PTS Change Control

Reason for Update	**Date**	**Notes**
Archived comments	6/10/2016	Order 822 was issued on January 21, 2016. The SC authorized posting the SAR and to request nominations for additional team members at March 9, 2016 meeting. The SAR posting ended April 21, 2016 and the SDT is reviewing the comments received. A CIP Technical Conference was held on April 19, 2016 in Atlanta. Seven additional members were appointed to the SDT at the April 20, 2016 SC meeting. Initial SDT meeting May 24-26, 2016 in Atlanta.
Added CIP Schedule for approval	7/20/2016	Update SC that schedule was approved by SDT, SDT leadership, developer, and PMOS Liaison. Second SAR posting was required due to expansion of scope.

Project	**2016-02**	**Home**
Project Name	Modifications to CIP Standards	
Status	Posted	
Comments	The standard is in initial posting for comment and ballot. Next steps, if standard passes, the SDT intends to repost for final ballot on January 30, 2017 ending on February 8, 2017.	
Deliverable	Directives, Control Center Comm Nets (CIP-006), TD at Lows (CIP-010 or CIP-003)	
Deadline	N/A	
Priority in 2016-2018 RSDP, if applicable (see Note 1)	High	
P81 Req (2013)	N/A	
Number of Directives	2	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Al McMeekin	
PMOS Liaison	Brian Murphy and Andrew Gallo	
Affected Standards	CIP-003-7(i)	
Last Updated	1/4/2017	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT							
QR - Quality Review	10/20/2016	10/30/2016	10/20/2016	10/30/2016			
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	12/12/2016	1/25/2017	12/2/2016	1/16/2017	(10)		
CAB - Com/Add Ballot 2	5/1/2017	6/15/2017	3/31/2017	5/15/2017	(31)		
CAB - Com/Add Ballot 3	8/15/2017	9/29/2017	8/15/2017	9/29/2017			

CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	10/17/2017	10/27/2017	10/17/2017	10/27/2017			
PTB - Present to BOT	11/7/2017	11/9/2017	11/7/2017	11/9/2017			
Filing - Filing with Regulators	12/28/2017	12/31/2017	12/28/2017	12/31/2017			
PT - Post Approval Training							

PTS Change Control

Reason for Update	**Date**	**Notes**
Archived comments	6/10/2016	Order 822 was issued on January 21, 2016. The SC authorized posting the SAR and to request nominations for additional team members at March 9, 2016 meeting. The SAR posting ended April 21, 2016 and the SDT is reviewing the comments received. A CIP Technical Conference was held on April 19, 2016 in Atlanta. Seven additional members were appointed to the SDT at the April 20, 2016 SC meeting. Initial SDT meeting May 24-26, 2016 in Atlanta.
Added CIP Schedule for approval	7/20/2016	Update SC that schedule was approved by SDT, SDT leadership, developer, and PMOS Liaison

Project	**2016-02**	**Home**
Project Name	Modifications to CIP Standards	
Status	Working to Comment Posting	
Comments	CIP subteams continue to draft rationale/purpose statements, consider requirement structures, Draft requirement language, take a close look at Measures.	
Deliverable	V5TAG issues: Cyber Asset and BES CA (BCA) definitions, Network and Externally Accessible Devices (ESP, ERC, IRA), TO Control Centers Performing Transmission Operator (TOP)	
Deadline	N/A	
Priority in 2016-2018 RSDP, if applicable (see Note 1)	High	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Al McMeekin	
PMOS	Brian Murphy and Andrew Gallo	
Affected Standards	CIP Stds. - Unknown	
Affected Standards	1/4/2017	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT							
QR - Quality Review	10/20/2016	10/30/2016	10/20/2016	10/30/2016			
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	***2/2/2017***	***3/19/2017***	12/2/2016	1/16/2017	(62)		
CAB - Com/Add Ballot 2	5/1/2017	6/15/2017	3/31/2017	5/15/2017	(31)		
CAB - Com/Add Ballot 3	8/15/2017	9/29/2017	8/15/2017	9/29/2017			

CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	10/17/2017	10/27/2017	10/17/2017	10/27/2017			
PTB - Present to BOT	11/7/2017	11/9/2017	11/7/2017	11/9/2017			
Filing - Filing with Regulators	12/28/2017	12/31/2017	12/28/2017	12/31/2017			
PT - Post Approval Training							

PTS Change Control

Reason for Update	**Date**	**Notes**
Archived comments	6/10/2016	Order 822 was issued on January 21, 2016. The SC authorized posting the SAR and to request nominations for additional team members at March 9, 2016 meeting. The SAR posting ended April 21, 2016 and the SDT is reviewing the comments received. A CIP Technical Conference was held on April 19, 2016 in Atlanta. Seven additional members were appointed to the SDT at the April 20, 2016 SC meeting. Initial SDT meeting May 24-26, 2016 in Atlanta.
Added CIP Schedule for approval	7/20/2016	Update SC that schedule was approved by SDT, SDT leadership, developer, and PMOS Liaison.

Project	**2016-EPR-01**	**Home**
Project Name	Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards	
Status	Posted	
Comments	Templates are posted for a 45-day formal comment period.	
Deliverable	PER-003-1 and PER-004-2	
Deadline	N/A	
Priority in 2016-2018 RSDP, if applicable (see Note 1)	N/A	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Darrel Richardson	
PMOS Liaison	Mike Brytowski	
Affected Standards	PER-003-1 and PER-004-2, but PER-001-0.2 was not evaluated due to retirement on April 17, 2017.	
Last Updated	1/10/2017	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR	2/10/2016	2/23/2016	2/10/2016	2/23/2016			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	1/10/2017	2/23/2017	1/23/2017	2/21/2017	13		
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							

CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
PMOS request	12/13/2017	List only the EPR nomination period and recommendation posting dates.

Project	**2016-EPR-02**	**Home**
Project Name	Enhanced Periodic Review of Voltage and Reactive Standards	
Status	Working to Comment Posting	
Comments	The team completed their review of the two VAR standards and completed each of the EPR templates during their January 3, 2017 conference call. The team will meet with the SRT the week of January 23, 2017 to affirm recommendations before posting for a 30-day informal comment period.	
Deliverable	VAR-001-4.1 & VAR-002-4	
Deadline	N/A	
Priority in 2016-2018 RSDP, if applicable (see Note 1)	N/A	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Scott Barfield-McGinnis	
PMOS Liaison	Amy Casuscelli	
Affected Standards	VAR-001-4.1 & VAR-002-4	
Last Updated	1/4/2017	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR	2/10/2016	2/23/2016	2/10/2016	2/23/2016			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	*1/31/2017*	*3/17/2017*	*1/31/2017*	*3/17/2017*			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							

CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
PMOS request	12/13/2017	List only the EPR nomination period and recommendation posting dates.

Project	**2016-03**	**Home**
Project Name	Cyber Security Supply Chain Management	
Status	Working to Comment Posting	
Comments	SDT is reviewing SAR comments and developing draft standard. The project will address directives from Federal Energy Regulatory Commission (FERC) Order No. 829 to develop a new or modified standard to address “supply chain risk management for industrial control system hardware, software, and computing and networking services associated with bulk electric system operations.” See Order No. 829, at P1. Projected initial posting Jan 19 - March 6, 2017. "Planned (internal)" 2nd posting (T) April 12 - May 26, 2017.	
Deliverable	New and revised Standard(s)	
Deadline	Wednesday, September 27, 2017	
Priority in 2016-2018 RSDP, if applicable (see Note 1)	N/A	
P81 Req (2013)	N/A	
Number of Directives	1	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Mark Olson	
PMOS Liaison	Brenda Hampton, Rod Kinard, and Angela Kimmey	
Affected Standards	New and revised Standard(s)	
Last Updated	1/4/2017	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT	7/29/2016	8/18/2016	7/29/2016	8/18/2016			
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	10/20/2016	11/18/2016	10/20/2016	11/21/2016			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							

CIB - Com/Ballot 1 (Initial)	***1/19/2017***	***3/6/2017***	***1/19/2017***	***3/6/2017***			
CAB - Com/Add Ballot 2	4/12/2017	5/26/2017	4/12/2017	5/26/2017			
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	6/21/2017	6/30/2017	6/21/2017	6/30/2017			
PTB - Present to BOT	8/9/2017	8/11/2017	8/9/2017	8/11/2017			
Filing - Filing with Regulators	9/24/2017	9/27/2017	9/24/2017	9/27/2017			
PT - Post Approval Training							

PTS Change Control

Reason for Update	**Date**	**Notes**
Create project record	8/1/2016	Added project to PTS.
Periodic Update	8/21/2016	Added FERC deadline
Baseline Schedule	11/30/2016	SDT determined the schedule.
Present Schedule to SC	1/18/2017	Accept SDT's project schedule

Project	**2016-04**	**Home**
Project Name	Modifications to PRC-025-1	
Status	SAR	
Comments	The Standards Authorization Request (SAR) to modify PRC-025-1 was posted for a 30-day formal comment period on September 16, 2016 along with a solicitation for SAR drafting team (DT) members. NERC received too few nominations initially. A second nomination period was posted from December 6-19, 2017. NERC will present vetted and recommended SAR DT candidates for appointments during the January 18, 2017 Standards Committee (SC) conference call. The SAR DT meetings are anticipated to be 2-3 conference calls due to the few comments received in the SAR posting period. Tentatively, calls would occur after the SC January meeting and the first week February 2017.	
Deliverable	PRC-025-2	
Deadline	None, enhancemens to 025 affects entities currently implementing version 1 under the five and seven year implementation period. The first period ends October 1, 2019 and the second on October 1, 2021. Project must consider the time for development and subsequent regulatory	
Priority in 2016-2018 RSDP, if applicable (see Note 1)	N/A	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	Yes	
Developer	Scott Barfield-McGinnis	
PMOS Liaison	Charles Yeung	
Affected Standards	PRC-025-1	
Last Updated	1/4/2017	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR	9/16/2016	9/28/2016	9/16/2016	9/28/2016			
Nominations - DT							
QR - Quality Review							

SP1 - SAR/PR/WP Posting 1	9/16/2016	10/18/2016	9/16/2016	10/18/2016			
SP2 - SAR/PR/WP Posting 2	***2/20/2017***	***3/22/2017***	***2/20/2017***	***3/22/2017***			
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	**Date**	**Notes**
SC Authorized Posting	9/14/2016	SAR and SAR SDT nominations.

No.	Description
Note 1	The prioritizations here reflect those prioritizations assigned as part of the 2015-2017 Reliability Standards Development Plan (RSDP). In its approach to prioritizing Reliability Standards projects, the RSDP considered how Reliability Standard family priorities are applied to individual projects and outstanding work. Specific elements included: (1) RISC Category Rankings; (2) regulatory directives; (3) regulatory deadlines; (4) Reliability Standard requirement candidates for retirement; (5) the IERP content and quality assessments; and (6) additional considerations (fill-in-the-blank status and five-year assessment commitments). Some projects were not prioritized in the RSDP, as they were originally anticipated to be complete before the end of the first quarter of 2015, and those projects have an "N/A" designation in this column. Other projects have been added to the Project Tracking Spreadsheet that were not prioritized in the RSDP. These were added in response to regulatory directives that were issued following completion of the RSDP, and they will be prioritized according to the same process during the first quarter of 2015 according to the same process described in the RSDP. Those projects are designated as "Pending Prioritization in 1Q 2015." As discussed in the 2015-2017 RSDP, the prioritization will occur in collaboration between NERC Staff and the Standards Committee.
Note 2	Refers to guidances from regulatory orders for standards activity to consider, but that do not carry the same effect as a directive.
Note 3	In the columns at right, in some cases, an "additional ballot" is not indicated for planning purposes, but if consensus is not supported on an initial ballot, or if substantive changes occur, one will be scheduled.
Note 4	In the columns at right, there are no "plan" milestones in some cases because the project was originally planned to be complete in 2014, and the project's "actual" milestones have extended into 2015).
Note 5	In the column labeled "directionally consistent with IERP findings," directionally consistent indicates whether the Standard Drafting Team, when the project is completed, considered the recommendations from the Independent Expert Review Project and the Paragraph 81 project. After the Standard Drafting Team has considered the recommendations, the materials posted with the standards will describe the Standard Drafting Team's consideration of the findings.
Note 6	Baseline - SC Approved project schedule. Current - Standards Developer managed schedule. Proposed - Not approved, used for planning purposes.
Note 7	
Note 8	
Note 9	
Note 10	

RSC Meeting #17-1, Agenda Item 4.0 Open Action Items

Item	Description	Owner	Due	Status
4.1	CIP-014 Feedback Loop Mechanism	Guy Zito	RSC Meeting	Ongoing
4.2	Si Truc Phan provide updates to the group on the status of GMD (Hydro Quebec Parameters)	Si Truc Phan	RSC Meeting	Ongoing
4.3	Collect all comments and updates for RSC Work Plan and Scope of Work	Ruida Shu	RSC Meeting	Completed

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Weekly Standards & Compliance Bulletin

February 27–March 5, 2017

ACTIVE STANDARDS POSTINGS

Current and Upcoming Ballots (ballot periods close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
Project 2016-03 – Cyber Security Supply Chain Risk Management | CIP-013-1	Initial Ballot and Non-binding Poll	02/24/17	03/06/17
Join Ballot Pools (ballot pool windows close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
--	--	--	--
Posted for Comment (comment periods close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
Project 2016-03 – Cyber Security Supply Chain Risk Management | CIP-013-1	Use comment form.	01/19/17	03/06/17
Project 2016-02 – Modifications to CIP Standards | Communication Networks	Use comment form.	02/10/17	03/13/17
Project 2016-02 – Modifications to CIP Standards | Modifications to Address CIP Exceptional Circumstances	Use comment form.	02/10/17	03/13/17

OTHER ACTIVE COMMENT PERIODS

Posted for Comment			
Posting	**Action**	**Start Date**	**End Date**
Comment Period Open for NPCC Quebec Regional Variance Revision to PRC-006-3: A comment period for PRC-006-3 – Automatic Underfrequency Load Shedding is open through March 1, 2017. This proposed revision to the NPCC Regional Variance specifically applies to the Quebec Region only. Due to the unique nature of the Quebec province being its own interconnection, the variance is being developed using the NPCC Regional Standard Processes Manual. Specifically, the "Section D. Regional Variance" and "Attachment 1A," which apply only to Quebec, have been revised to reflect the unique nature of the Quebec interconnection.	Comments may be submitted electronically through the NPCC website.	01/20/17	03/01/17

STANDARDS NEWS

UPDATED Save the Date for 2017 NERC Standards and Compliance Workshop

The 2017 NERC Standards and Compliance Workshop will be held July 11–12 in New Orleans and will present stakeholders with valuable information about standards development, compliance monitoring and operations, and other initiatives.

An optional NERC Standards and Compliance 101 presentation will be offered in person and via webinar on July 11, 2017 and is tentatively scheduled from 9:00 a.m. to Noon Central. This presentation is free and provides background on NERC processes for stakeholders that are less familiar with NERC standards and compliance activities.

QUICK LINKS

Register in the SBS
Original Balloting Software
Projected Standards Posting Schedule
Project Tracking Spreadsheet
Standards Related Questions – Single Portal
2016–2018 Reliability Standards Development Plan

The 2017 Standards and Compliance Workshop is tentatively scheduled to run from 8:00 a.m. to 5:00 p.m. Central on July 11 and July 12. This workshop will present stakeholders with valuable information about standards development, the cost effectiveness pilot, training on standards going into effect and recently approved by FERC, compliance guidance updates, and other initiatives. The fee is US$350 in-person attendance and US$125 for webinar attendance.

Please note that only one NERC Standards and Compliance Workshop will take place in 2017. Hotel and workshop registration links are available in the Upcoming Events section.

UPDATED Standards Balloting and Commenting System Enhancements Deployed

Enhancements to the Standards Balloting and Commenting System (SBS) were deployed on February 21, 2017. The SBS enhancement features included:

- All voting-related functions located on the "Ballot Events" page;
- The term "Survey" replaced with the term "Comment Form";
- Proceed directly to the "Real-time Comments" page without submitting a comment;
- Select members from the Registered Ballot Body when creating groups;
- No confirmation necessary for negative opinions for non-binding poll ballot types; and
- Sort and/or filter views on all pages retained.

An informational webinar was held February 14, 2017, and the Slide Presentation and streaming webinar are now available.

Standards Database and Website Updates Coming Soon

NERC Standards staff is pleased to announce updates to the Standards web pages coming soon. The go-live date will be announced once confirmed, and a webinar will be scheduled to provide details on each update and location.

Updates will include:

- **"Effective Date" replaces "Enforcement Date"**

- The term “Enforcement Date” will be replaced by “Effective Date of Standard” when referencing the date the Reliability Standard becomes mandatory and enforceable.
- **Update locations:** U.S. Enforcement Dates web page, U.S. Enforcement Status/Functional Applicability spreadsheet, and One-Stop Shop

- **Standards Status – Pending Inactive**
  - A standard becomes **Pending Inactive** once determined that it will not become enforceable and has been superseded by another standard. The status will change to inactive at midnight on the day immediately prior to the effective date of the superseding standard.
  - **Update locations:** Reliability Standards web page, Enforcement Dates web page, U.S. Enforcement Status/Functional Applicability spreadsheet, and One-Stop Shop

- **Phased-In Implementation Date (if applicable)**:
  - This date, which follows the Effective Date of the Reliability Standard, identifies the implementation of a specific Requirement (or part), as specified in the Implementation Plan for the Reliability Standard. This date represents the date that entities must become compliant.
  - **Update location:** The “Detail” link on the Enforcement Dates web page will include the Phased-in Implementation Date, if this date is different than the Effective Date of the main standard.

Example of “Detail” link on Enforcement Dates web page:

Standard: CIP-003-6				
Requirement	**Effective Date Of Standard**	**Phased-in Implementation Date (if applicable)**	**Inactive**	**Notes**
R1.	7/1/2016			
1.1.	7/1/2016			
1.1.2.	7/1/2016			
1.1.3.	7/1/2016			
1.2.		4/1/2017		

1.2.1.		4/1/2017		
1.2.2.		4/1/2017		

This example does not include all Requirements and parts.

Please direct any questions regarding the updates to Monica Bales.

GENERAL COMPLIANCE AND ENFORCEMENT NEWS

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

NEW NERC Publishes Analysis of Serious Risk Violations with an Impact Report

NERC analyzes noncompliance at all risk levels to identify patterns, trends, and areas of focus. This work is conducted through close collaboration with ERO Enterprise staff from the eight REs, internal NERC departments, and program areas such as Compliance Assurance and Reliability Risk Management.

This *Analysis of Serious Risk Violations with an Impact* report is an overview of serious risk violations that had an observable impact on the reliability of the BPS. The analysis in this report intends to complement the two metrics developed by the Compliance and Certification Committee (CCC) in 2015: CP-1 (count of serious risk violations by quarter of occurrence) and CP-2 (count of “Impactful” violations by quarter of occurrence). The report presents frequently observed issues from these violations and includes associated recommendations that may benefit industry when evaluating risks and assessing their internal controls. The information in this report can also be used by registered entities to optimize their overall reliability programs and improve compliance with NERC Reliability Standards. This document is for informational purposes and is not intended to establish new requirements or mandates under NERC’s Reliability Standards or the NERC Compliance Monitoring and Enforcement Program (CMEP). This report is based on the publicly available noncompliance information posted on the NERC website under the Enforcement and Mitigation page.

NEW NERC Compliance Filings

On February 21, 2017, NERC submitted to FERC its 2016 ERO Enterprise CMEP Annual Report and Petition, which included a request for enhancements to the risk-based CMEP.

NERC’s 2017 filings to FERC are available here.

Nomination Period for Compliance and Certification Committee Open

The Compliance and Certification Committee (CCC) is requesting nominations to fill one position. In the capacity of a NERC Board-appointed stakeholder committee serving and reporting directly to the NERC Board, the CCC will engage with, support, and advise the NERC Board and NERC regarding all facets of the NERC Compliance Monitoring and Enforcement Program, Organization Registration Program, and Organization Certification Program. Nominations are being accepted through March 7, 2017.
The following position is currently open for nominations to the CCC:

Voting Position:

- Merchant Electricity Generator

The CCC has an open nomination process. Individuals or recognized industry groups may nominate candidates for consideration. Terms will be for three years and will begin interim membership after acceptance by the CCC Nominating Subcommittee and approval by the CCC, and full membership after NERC Board approval of membership appointments at its scheduled meetings. The next 2017 CCC scheduled meeting is March 15–16, 2017 in Atlanta, GA. Please review the CCC Charter for information regarding the responsibilities of CCC members.

If you are interested in serving as or nominating a member to the NERC Compliance and Certification Committee, please complete the nomination form and send it to CCCElections@nerc.net by **March 7, 2017.**

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)
April 1, 2017	CIP-003-6 – Cyber Security – Security Management Controls (Requirements 1.2–2); CIP-010-2 – Cyber Security — Configuration Change Management and Vulnerability Assessments (Requirement 4)
	EOP-004-3 – Event Reporting; EOP-010-1 – Geomagnetic Disturbance Operations (Requirement 2); EOP-011-1 – Emergency Operations;
	FAC-010-3 – System Operating Limits Methodology for the Planning Horizon; FAC-011-3 – System Operating Limits Methodology for the Operations Horizon;

	IRO-001-4 – Reliability Coordination: Responsibilities; IRO-002-4 – Reliability Coordination: Monitoring and Analysis; IRO-008-2 – Reliability Coordinator Operational Analyses and Real-time Assessments; IRO-010-2 – Reliability Coordinator Data Specification and Collection (Requirement R3); IRO-014-3 – Coordination Among Reliability Coordinators; IRO-017-1 – Outage Coordination;
	MOD-029-2a – Rated System Path Methodology; MOD-030-3 – Flowgate Methodology;
	PRC-010-1 – Undervoltage Load Shedding; PRC-004-WECC-2 – Protection System and Remedial Action Scheme Misoperation; PRC-015-1 – Remedial Action Scheme Data and Documentation; PRC-016-1 – Remedial Action Scheme Misoperations; PRC-017-1 – Remedial Action Scheme Maintenance and Testing; PRC-023-4 – Transmission Relay Loadability
	TOP-001-3 – Transmission Operations; TOP-002-4 – Operations Planning; TOP-003-3 – Operational Reliability Data (Requirement R5);
April 2, 2017	PRC-004-5(i) – Protection System Misoperation Identification and Correction; PRC-010-2 – Undervoltage Load Shedding;
July 1, 2017	CIP-004-6 – Cyber Security – Personnel & Training (Requirements 2.3, 4.3, 4.4); CIP-006-6 – Cyber Security — Physical Security of BES Cyber Systems (Requirement 3.1); CIP-008-5 – Cyber Security — Incident Reporting and Response Planning (Requirement 2.1); CIP-009-6 – Cyber Security — Recovery Plans for BES Cyber Systems (Requirement 2.1–2.2); CIP-010-2 – Cyber Security — Configuration Change Management and Vulnerability Assessments (Requirement 3.1);
	MOD-033-1 – Steady-State and Dynamic System Model Validation;
	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events
October 1, 2017	COM-001-3 – Communications

January 1, 2018	PRC-026-1 – Relay Performance During Stable Power Swings (Requirement 1);
April 1, 2018	IRO-018-1 – Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities
	TOP-010-1 – Real-time Reliability Monitoring and Analysis Capabilities
July 1, 2018	CIP-009-6 – Cyber Security — Recovery Plans for BES Cyber Systems (Requirement 2.3); CIP-010-2 – Cyber Security — Configuration Change Management and Vulnerability Assessments (Requirements 3.2, 3.2.1, 3.2.2);
	MOD-026-1 – Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions (Requirements 2, 2.1–2.1.6); MOD-027-1 – Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions (Requirements 2, 2.1–2.1.5);
	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirement 2)
January 1, 2019	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirement 5)
January 1, 2020	PRC-026-1 – Relay Performance During Stable Power Swings (Requirements 2–4)
January 1, 2021	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirements 6, 6.1–6.4)
January 1, 2022	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirements 3,4,7)
July 1, 2022	PRC-002-2 – Disturbance Monitoring and Reporting Requirements (Requirements 2–4, 6–11)

BOARD OF TRUSTEES AND FERC ACTION

There is no additional Board or FERC action to report for this week.

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

- 2017 Reliability Leadership Summit – March 21, 2017, Washington, D.C. | Registration and Hotel Information
- Sixth Annual Human Performance Conference and Workshops – March 28–30, 2017, Atlanta | Register for Conference and Workshops | Register for Hotel
- **NEW** Power System Modeling Workshop Technical Conference – June 20–21, 2017, Oak Brook, IL | Conference Registration
- **UPDATED** 2017 Standards and Compliance Workshop – July 11–12, 2017, New Orleans, LA | **NEW** In-person Workshop Registration | **NEW** Webinar Workshop Registration | **NEW** Hotel Registration

Webinars

There are no webinars currently scheduled.

Standing Committee Meetings and Conference Calls

- Operating Committee, Planning Committee, and Critical Infrastructure Protection Committee Meetings – March 7–9, 2017, Atlanta | Register for OC | Register for PC | Register for CIPC | Register for Hotel
- Standards Committee Meeting – 10:00 a.m.–3:00 p.m. Mountain, March 15, 2017, Salt Lake City, UT | Register
- Reliability Issues Steering Committee – 8:00 a.m.–Noon Eastern, March 22, 2017, Washington, D.C. | Register

Standard Drafting Team Meetings

The Standards calendar provides dial-in information for the in-person meetings below. The calendar also provides information about conference calls that drafting teams may hold in addition to in-person meetings.

- Project 2013-03 – Geomagnetic Disturbance Mitigation Standards Drafting Team Meeting – February 27–March 1, 2017, Austin, TX | Registration and Meeting Details
- Project 2016-03 – Cyber Security Supply Chain Risk Management Standard Drafting Team – March 14–16, 2017, San Antonio, TX | Registration and Meeting Details

- **NEW** Project 2016-02 – Modifications to CIP Standards Drafting Team – March 21–23, 2017, Houston, TX | Registration and Meeting Details

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 Amy Desselle 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.

UPDATED If you would like to receive this bulletin or be added to the distribution list for a particular standards project, please register through our ERO portal. For more information about any of the compliance news listed in the bulletin, please contact Tiffany Whaley.

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Standards Balloting and Commenting System (SBS)

Description of Enhancements
January 2017

RELIABILITY | ACCOUNTABILITY

Overview

- Enhancements to the SBS are currently being tested and are scheduled to be deployed late February 2017.
- This presentation provides a description of the upcoming enhancements.
- A training webinar will be held prior to deployment. Once a date is solidified, the webinar will be posted to the NERC calendar and an announcement will be distributed to the industry.

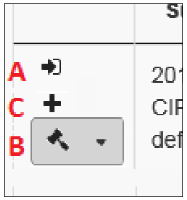
Upcoming Enhancements

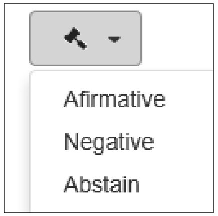
- Ability for users to vote, delegate/revoke proxy rights, and join ballots/ballot pools from the “View Ballot Events” page
- All current references to the term “Survey” will be replaced with the term “Comment Form”
- Ability for users to proceed directly to the “Real-time Comments” page (“Social Survey”) without first having to provide a response
- Ability for users to select members from the Registered Ballot Body (RBB) when creating groups
- Users will no longer be prompted to confirm negative votes (opinions) for non-binding Poll ballot types
- The system will save users’ selected sorting/filter view on all pages instead of reverting back to a default view

“View Ballot Events” Page

- Voters will have the ability to perform the the following functions directly from the “View Ballot Events” page:
  - Join/withdraw from ballot pools
  - Delegate/revoke proxies
  - Vote for ballots
- New icon/function buttons will be added to the page (screenshots below)
- The “My Voting Activity” page will be removed

A and D – Join and withdraw from ballot pool
B – Vote
C and E – Delegate and revoke proxy rights





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Change of the Term "Survey" to "Comment Form"

- Currently, the system refers to comment forms as "Surveys". The terms "Survey"/"Take Survey" will be replaced with the more familiar terms "Comment Forms"/"Submit Comments" for consistency between Standards' communications/postings and the SBS.

“Real-time Comments” Page

- Currently, users who try to access the “Real-time Comments” page (“Social Survey”) without first submitting comments receive the following message:

- Voters, proxies, and contributors will have the ability to provide a thumbs-up (like), thumbs-down (dislike) to another submitters’ comments without having to provide a response themselves

RBB Members and Creating Groups

- A filter box will be added to the “Create a Group” page so that voters, proxies, and contributors can select members of the current RBB when creating groups
- The ability to manually enter/edit group members will remain

Negative Vote Confirmation for Non-binding Poll Ballot Types

- Negative votes/opinions for non-binding polls do not require an associated comment. Therefore, the verification pop-up will be eliminated. Voters and proxies will not be prompted to comment or declare support for a third-party comment.

Sort and Filter

- When users navigate away from a page and then return, the system will retain any selected filtered and/or sorted results. Once users log out, the sort/filter selection will revert to the default state.

Standards Information Links

- SBS Quick Reference Guide
- NERC's Balloting and Commenting page
- Administrative Support: ballotadmin@nerc.net
- NERC IT Support: https://support.nerc.net/
- Standard Processes Manual
- Appendix 3D – RBB Criteria
- SBS Training
- Frequently Asked Questions

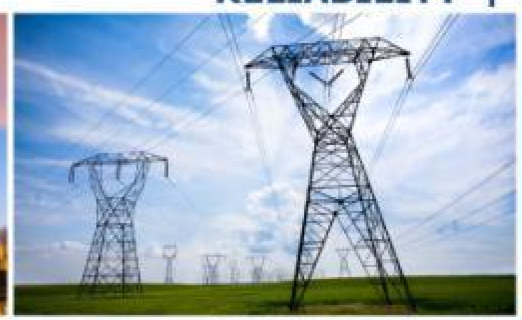
NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Balloting and Commenting System (SBS) Enhancement Feature Overview and Training

Wendy Muller, Specialist, Standards Development
February 14, 2017

RELIABILITY | ACCOUNTABILITY





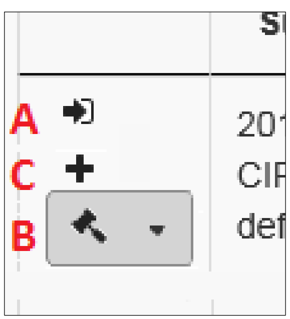

2017 Enhancement Features

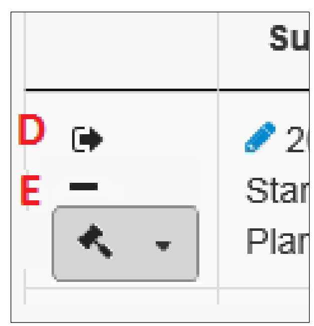
- Ability for users to vote, delegate/revoke proxy rights, and join ballots/ballot pools from the "Ballot Events" page
- All references to the term "Survey" will be replaced with the term "Comment Form"
- Ability for users to proceed directly to the "Real-time Comments" page (formerly "Social Survey") without first having to provide a response
- Ability for users to select members from the Registered Ballot Body (RBB) when creating groups
- Users will no longer be prompted to confirm negative opinions for Non-binding Polls
- The system will save users' selected sort and/or filter view on all pages instead of reverting back to a default view

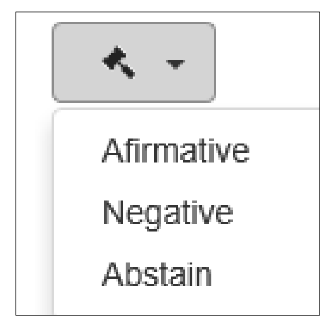
"Ballot Events" Page

- The "My Voting Activity" page will be removed and the voting-related functions listed below will be carried out on the "Ballot Events" page:
  - Join/withdraw from ballot pools
  - Delegate/revoke proxies
  - Vote for ballots
- New icon/function buttons will be added to the page (screenshots below)

A and D – Join and withdraw from ballot pool
B – Vote
C and E – Delegate and revoke proxy rights







Change of the Term “Survey” to “Comment Form”

- Terms such as “Surveys” and “Take Survey” will be replaced with the terms “Comment Form” and “Submit Comments” for consistency between Standards’ communications/postings and the SBS

“Real-time Comments” Page

- The current term/page, “Social Survey” has been renamed “Real-time Comments”. Today, users who try to access this page without first submitting comments receive the following error message:

- Voters, proxies, and contributors will have the ability to provide a thumbs-up (like), thumbs-down (dislike) to other submitters’ comments without having to provide a response themselves.

RBB Members and Creating Groups

- When submitting a comment, users will have the ability to select current RBB members when creating groups
- The ability to manually enter/edit group members will remain

Negative Opinions and Confirmations for Non-binding Polls

- For non-binding poll ballot types, voters and proxies will not be prompted to comment or declare support for a third-party comment if a negative opinion is cast

Sort and Filter

- Any filtered and/or sorted results will be retained when navigating between SBS pages
- Once a user logs out of the SBS, the filtered and/or sorted selection will revert to a default state

Standards Information Links

- NERC's Balloting and Commenting page
- SBS Quick Reference Guide
- SBS Tutorial
- 2017 SBS Enhancement Presentation slides
- Administrative Support: ballotadmin@nerc.net
- NERC IT Support: https://support.nerc.net/
- Standard Processes Manual
- Appendix 3D – RBB Criteria

2017 Enhancement Features Recap

- All vote-related functions located on the "Ballot Events" page
- The term "Survey" replaced with the term "Comment Form"
- Proceed directly to the "Real-time Comments" page without submitting a comment
- Select members from the Registered Ballot Body (RBB) when creating groups
- No confirmation necessary for negative opinions for Non-binding Polls
- Sort and/or filter view on all pages will be retained

Deployment Schedule

- Enhancements to the SBS are scheduled to be deployed the evening of February 20, 2017
- Enhancements will be live the morning of February 21, 2017

Questions and Answers

158 FERC ¶ 61,042
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM16-20-000]

Remedial Action Schemes Reliability Standard

(January 19, 2017)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission proposes to approve Reliability Standard PRC-012-2 (Remedial Action Schemes) submitted by the North American Electric Reliability Corporation. The purpose of proposed Reliability Standard PRC-012-2 is to ensure that remedial action schemes do not introduce unintentional or unacceptable reliability risks to the bulk electric system.

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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Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
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Alan.Rukin@ferc.gov

SUPPLEMENTARY INFORMATION:

158 FERC ¶ 61,042
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Remedial Action Schemes Reliability Standard Docket No. RM16-20-000

NOTICE OF PROPOSED RULEMAKING

(January 19, 2017)

1. Pursuant to section 215 of the Federal Power Act (FPA), the Commission proposes to approve proposed Reliability Standard PRC-012-2 (Remedial Action Schemes). The North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), submitted proposed Reliability Standard PRC-012-2 for approval. The purpose of proposed Reliability Standard PRC 012-2 is to ensure that remedial action schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the bulk electric system. In addition, the Commission proposes to approve the associated violation risk factors and violation severity levels, implementation plan, and effective date proposed by NERC. NERC also submitted proposals to retire two currently-effective Reliability Standards and to withdraw three Reliability Standards that are pending review before the Commission. While proposing to approve Reliability Standard PRC-012-2, the Commission seeks clarifying comments addressing “limited impact” RAS. Based on comments and information received, the Commission may issue directives as appropriate.

I. Background

A. Section 215 and Mandatory Reliability Standards

2. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval.[1] Once approved, the Reliability Standards may be enforced by the ERO subject to Commission oversight, or by the Commission independently.[2] In 2006, the Commission certified NERC as the ERO pursuant to section 215 of the FPA.[3]

B. Order No. 693

3. On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 Reliability Standards filed by NERC, including Reliability Standards PRC-015-1 (Remedial Action Scheme Data and Documentation) and PRC-016-1 (Remedial Action Scheme Misoperation).[4] Reliability Standard PRC-015-1 requires transmission owners, generator owners, and distribution providers to maintain a listing; retain evidence of review; and provide documentation of existing, new or functionally modified special

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[1] 16 U.S.C. 824o(c), (d) (2012).

[2] *Id.* 824o(e).

[3] *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), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[4] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. and Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

protection systems.[5] Reliability Standard PRC-016-1 requires transmission owners, generator owners, and distribution providers to provide the regional reliability organization with documentation, analyses and corrective action plans for misoperation of special protection systems.[6]

4. In Order No. 693, the Commission determined that proposed Reliability Standard PRC-012-0 was a "fill-in-the-blank" Reliability Standard because, while it was proposed to require regional reliability organizations to ensure that all special protection systems are properly designed, meet performance requirements, and are coordinated with other protection systems, NERC had not submitted any regional review procedures with this standard.[7] The Commission also determined that proposed Reliability Standard PRC-013-0 was a "fill-in-the-blank" Reliability Standard because, although it was proposed to ensure that all special protection systems are properly designed, meet performance requirements, and are coordinated with other protection systems by requiring the regional reliability organization to maintain a database of information on special protection systems, NERC had not filed any regional procedures for maintaining

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[5] *Id.* PP 1529-1533.

[6] *Id.* PP 1534-1540.

[7] *Id.* PP 1517-18, 1520. The Commission used the term "fill-in-the-blank" standards to refer to proposed Reliability Standards that required the regional reliability organizations to develop at a later date criteria for use by users, owners or operators within each region. *Id.* P 297.

the databases.[8] Further, the Commission determined that proposed Reliability Standard PRC-014-0 was a "fill-in-the-blank" Reliability Standard because, while it was proposed to ensure that special protection systems are properly designed, meet performance requirements, and are coordinated with other protection systems by requiring the regional reliability organization to assess and document the operation, coordination, and compliance with NERC Reliability Standards and effectiveness of special protection systems at least once every five years, NERC had not submitted any regional procedures for this assessment and documentation.[9] The Commission stated that it would not approve or remand proposed Reliability Standards PRC-012-0, PRC-013-0 or PRC-014-0 until NERC submitted the additional necessary information to the Commission.[10]

C. Remedial Acton Schemes

5. On June 23, 2016, the Commission approved NERC's revision to NERC Glossary of Terms that redefines special protection system to have the same definition as RAS, effective April 1, 2017.[11] Effective April 1, 2017, the NERC Glossary of Terms will define Remedial Action Scheme to mean:

> A scheme designed to detect predetermined System

[8] *Id.* PP 1521, 1522, 1524.

[9] *Id.* PP 1525, 1526, 1528.

[10] *Id.* PP 1520, 1524, 1528.

[11] *N. Am. Elec. Reliability Corp.*, Docket No. RD16-5-000 (June 23, 2016) (delegated letter order); NERC Glossary of Terms, http://www.nerc.com/files/glossary_of_terms.pdf.

conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as:

- Meet requirements identified in the NERC Reliability Standards;
- Maintain Bulk Electric System (BES) stability;
- Maintain acceptable BES voltages;
- Maintain acceptable BES power flows;
- Limit the impact of Cascading or extreme events.[12]

The revised RAS definition also identifies fourteen items that do not individually constitute a RAS.

D. NERC Petition and Proposed Reliability Standard PRC-012-2

6. On August 5, 2016, NERC submitted a petition seeking Commission approval of proposed Reliability Standard PRC-012-2.[13] NERC contends that proposed Reliability Standard PRC-012-2 is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[14] NERC explains that the intent of proposed Reliability Standard PRC-012-2 is to supersede "pending" Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1 and to retire and replace currently-effective Reliability Standards PRC-015-1

[12] NERC Glossary of Terms, http://www.nerc.com/files/glossary_of_terms.pdf; *see also Revisions to Emergency Operations Reliability Standards; Revisions to Undervoltage Load Shedding Reliability Standards; Revisions to the Definition of "Remedial Action Scheme" and Related Reliability Standards*, Order No. 818, 153 FERC ¶ 61,228, at PP 24, 31 (2015).

[13] Proposed Reliability Standard PRC-012-2 is not attached to this Notice of Proposed Rulemaking. The proposed Reliability Standard is available on the Commission's eLibrary document retrieval system in Docket No. RM16-20-000 and is posted on NERC's website, http:// www.nerc.com.

[14] NERC Petition at 2.

and PRC-016-1.[15] NERC states that proposed Reliability Standard PRC-012-2 represents substantial improvements over these Reliability Standards because it streamlines and consolidates existing requirements; corrects the applicability of previously unapproved Reliability Standards; and implements a continent-wide RAS review program.[16]

7. NERC states that, in the United States, proposed Reliability Standard PRC-012-2 will apply to reliability coordinators, planning coordinators, and RAS-entities. Proposed Reliability Standard PRC-012-2 defines RAS-entities to include the transmission owner, generation owner, or distribution provider that owns all or part of a RAS.

8. NERC states that proposed Reliability Standard PRC-012-2 includes nine requirements that combine all existing (both effective and "pending") Reliability Standards into a single, consolidated, continent-wide Reliability Standard to address all aspects of RAS.[17] NERC states that all of the requirements in Reliability Standard PRC-012-1 except R2 are now covered in Requirements R1, R2, R3, R4, R5, R6, and R8 of proposed Reliability Standard PRC-012-2.[18] NERC explains that Reliability Standard PRC-012-1, Requirement R2 is "administrative in nature and does not contribute to

[15] NERC notes that it submitted "for completeness" revised versions of Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1 in its petition to revise the definition of RAS, but NERC did not request Commission approval of the revised Reliability Standards in that proceeding. *Id.* at 1 n.5.

[16] *Id.* at 12-13.

[17] *Id.* at 3.

[18] *Id.* at 40.

reliability."[19] NERC also states that it established Requirement R9 of proposed Reliability Standard PRC-012-2 to replace the mandate in Reliability Standard PRC-013-1 that responsible entities maintain a RAS database with pertinent technical information for each RAS.[20] NERC explains that proposed Reliability Standard PRC-012-2 Requirements R4 and R6 cover the review and the mandate to take corrective action required by Reliability Standard PRC-014-1.[21] NERC states that it integrated the performance requirements in Reliability Standard PRC-015-1 into proposed Reliability Standard PRC-012-2 Requirements R1, R2, and R3.[22] NERC maintains that it integrated the performance requirements in Reliability Standard PRC-016-1 into proposed Reliability Standard PRC-012-2 Requirements R5, R6, and R7.[23]

9. NERC explains how the nine Requirements in proposed Reliability Standard PRC-012-2 work together and with other Reliability Standards. Proposed Requirements R1, R2, and R3, together, establish a process for the reliability coordinator to review new or modified RAS schemes.[24] The reliability coordinator must complete the review before an entity places a new or functionally modified RAS into service.

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[19] *Id.* at 41.

[20] *Id.* at 42.

[21] *Id.* at 43.

[22] *Id.* at 43-44.

[23] *Id.* at 44-45.

[24] *Id.* at 15-18.

10. Proposed Requirement R4 requires the planning coordinator to perform a periodic evaluation of each RAS within its planning area, at least once every five years.[25] The evaluation must determine, *inter alia*, whether each RAS: (1) mitigates the system conditions or contingencies for which it was designed; and (2) avoids adverse interactions with other RAS and protection systems. Proposed Requirement R4, Part 4.1.3 footnote 1 defines a certain subset of RAS as "limited impact" RAS to mean "A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations."[26] Further, proposed Requirement R4, Parts 4.1.3, 4.1.4, and 4.1.5 provide certain exceptions to "limited impact" RAS. For example, Part 4.1.5 states that:

> Except for limited impact RAS, a single component failure in the RAS, when the RAS is intended to operate does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed.[27]

NERC explains that proposed Requirement R4 "does not supersede or modify [planning coordinator] responsibilities under Reliability Standard TPL-001-4."[28] NERC continues

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[25] *Id.* at 18-22.

[26] *Id.* at 19 & n.44.

[27] *Id.* at 19.

[28] *Id.* at 28.

that even though Part 4.1.5 exempts "limited impact" RAS from certain aspects of proposed Requirement R4, proposed Reliability Standard PRC-012-2 does not exempt "limited impact" RAS from meeting each of the performance requirements in Reliability Standard TPL-001-4.[29]

11. NERC states that prior to development of proposed Reliability Standard PRC-012-2, two NERC Regions, the Northeast Power Coordinating Council (NPCC) and the Western Electric Coordinating Council (WECC), used individual RAS classification regimes to identify RAS that would meet criteria similar to those for RAS described as "limited impact" in proposed Reliability Standard PRC-012-2.[30] NERC continues that the standard drafting team identified the Local Area Protection Scheme (LAPS) classification in WECC and the Type III classification in NPCC as consistent with the "limited impact" designation.[31] According to NERC, RAS implemented prior to the effective date of proposed Reliability Standard PRC-012-2 that have gone through the regional review processes of WECC or NPCC and that are classified as either a LAPS by WECC or a Type III by NPCC, would be considered a "limited impact" RAS for purposes of proposed Reliability Standard PRC-012-2.[32]

[29] *Id.* at 28-29.

[30] *Id.* at 25.

[31] *Id.* at 25-26.

[32] *Id.* at 26.

12. Proposed Requirements R5, R6, and R7 pertain to the analysis of each RAS operation or misoperation.[33] The RAS-entity must perform an analysis of each RAS operation or misoperation and provide the results to the reviewing reliability coordinator. Further, the RAS-entity must develop and submit a corrective action plan to the reviewing reliability coordinator after learning of a deficiency with its RAS, implement the corrective action plan, and update it as necessary. Proposed Requirement R8 requires periodic testing of RAS performance: every six years for normal RAS and 12 years for "limited impact" RAS.[34] Proposed Requirement R9 requires the reliability coordinator to annually update its RAS database.[35]

13. NERC proposes an implementation plan that includes an effective date for proposed Reliability Standard PRC-012-2 that is the first day of the first calendar quarter that is thirty-six months after the date that the Commission approves the proposed Reliability Standard. Concurrent with the effective date, the implementation plan calls for the retirement of currently-effective Reliability Standards PRC-015-1 and PRC-016-1 and withdrawal of "pending" Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1.

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[33] *Id.* at 29-34.

[34] *Id.* at 34-36.

[35] *Id.* at 36-38.

II. Discussion

14. Pursuant to section 215(d)(2) of the FPA, we propose to approve proposed Reliability Standard PRC-012-2 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. We also propose to approve the associated violation risk factors and violation severity levels, implementation plan, and effective date proposed by NERC. Further, we propose to approve the withdrawal of "pending" Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1 and retirement of currently-effective Reliability Standards PRC-015-1 and PRC-016-1, as proposed by NERC.

15. Proposed Reliability Standard PRC-012-2 enhances reliability by addressing all aspects of RAS in a single, continent-wide Reliability Standard and by assigning specific RAS responsibilities to appropriate functional entities. Accordingly, proposed Reliability Standard PRC-012-2 satisfies the relevant directive in Order No. 693. In addition, we agree with NERC that Reliability Standards PRC-015-1 and PRC-016-1 can be retired as proposed in the implementation plan due to their consolidation with proposed Reliability Standard PRC-012-2.

16. NERC's petition states that proposed Reliability Standard PRC-012-2 does not exempt "limited impact" RAS from meeting all system performance requirements of Reliability Standard TPL-001-4. We propose to clarify that, consistent with NERC's explanation, proposed Reliability Standard PRC-012-2 will not modify or supersede any

system performance obligations under Reliability Standard TPL-001-4.[36] For example, under Reliability Standard TPL-001-4, Table 1 non-consequential load loss may not exceed 75 MW for certain Category P1, P2, or P3 contingencies following the Reliability Standard TPL-001-4 stakeholder process.[37] We seek comment on this proposal.

17. We also seek comment on the processes used to ensure the LAPS or Type III RAS will be compliant with Reliability Standard TPL-001-4 prior to the effective date of Reliability Standard PRC-012-2, including a description of considerations on whether the load disconnected by each RAS installation is consequential or non-consequential, and if non-consequential load loss is greater than 75 MW.[38] We further seek comment on whether the term "limited impact RAS" should be defined in the Glossary of Terms Used in NERC Reliability Standards.

III. Information Collection Statement

18. The collection of information addressed in this Notice of Proposed Rulemaking is subject to review by the Office of Management and Budget (OMB) under section 3507(d)

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[36] *See* NERC Petition at 28 ("Requirement R4 of PRC-012-2 does not supersede or modify [planning coordinator] responsibilities under Reliability Standard TPL-001-4…").

[37] Reliability Standard TPL-001-4, Table 1 (Steady State & Stability Performance Extreme Events), footnote 12 and Attachment 1.

[38] The Commission notes that WECC's and NPCC's RAS criteria and associated regional terms found in the "Technical Justification" section of proposed Reliability Standard PRC-012-2 were not submitted for approval by NERC and as such are not part of this proceeding.

of the Paperwork Reduction Act of 1995.[39] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[40] 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. The Commission will submit the information collection requirement to OMB for its final review and approval. The Commission solicits public comments on the 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.

20. The information collection requirements in this Notice of Proposed Rulemaking in Docket No. RM16-20-000 is associated with FERC-725A (OMB Control No. 1902-0244) and FERC-725G (OMB Control No. 1902-0252).

21. Public Reporting Burden: The Commission proposes to approve Reliability Standard PRC-012-2. The proposed Reliability Standard PRC-012-2 consolidates so-called "fill-in-the-blank" Reliability Standards PRC-012-1, PRC-013-1 and PRC-014-1, as well as, Commission-approved Reliability Standards PRC-015-1 and PRC-016-1, into

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[39] 44 U.S.C. 3507(d) (2012).

[40] 5 CFR 1320.11 (2016).

one standard. The proposed Reliability Standard PRC-012-2 improves upon the existing standards because it removes ambiguity in NERC's original "fill-in-the-blank" Reliability Standards by assigning responsibility to appropriate functional entities. It also streamlines and consolidates the RAS Reliability Standards into one clear, effective Reliability Standard. The number of respondents below is based on an examination of the NERC compliance registry for reliability coordinators, planning coordinators, transmission owners, generation owners, and distribution providers and an estimation of how many entities from that registry will be affected by the proposed Reliability Standard. At the time of Commission review of proposed Reliability Standard PRC-012-2, 15 reliability coordinators, 71 planning coordinators, 328 transmission owners, 930 generation owners, and 367 distribution providers in the United States were registered in the NERC compliance registry. However, under NERC's compliance registration program, entities may be registered for multiple functions, so these numbers incorporate some double counting. The Commission notes that many generation sites share a common generation owner. The following table illustrates the estimated burden to be applied to the information collection.[41]

[41] In the burden table, engineering is abbreviated as "Eng." and record keeping is abbreviated as "R.K."

RM16-20-000 (Mandatory Reliability Standards: Reliability Standard PRC-012-2)					
Requirement and Respondent Category for PRC-012-2	**Number of Respondents (1)**	**Number of Responses per Respondent (2)**	**Total Number of Responses (1)*(2)=(3)**	**Average Burden Hours & Cost per Response[42] (4)**	**Annual Burden Hours & Total Annual Cost (3)*(4)=(5)**
R1. Each RAS-entity (TO, GO, DP)	1,595	1	1,595	(Eng.) 24 hrs. ($1,543); (R.K.) 12 hrs. ($453)	57,420 hrs. (38,280 Eng., 19,140 R.K.); $3,183,556 ($2,461,021 Eng., $722,535 R.K.)
R2. Each Reliability Coordinator	15	1	15	(Eng.) 16 hrs. ($1,029); (R.K.) 4 hrs. ($151)	300 hrs. (240 Eng., 60 R.K.); $17,695 ($15,430 Eng., $2,265 R.K.)
R4. Each Planning Coordinator	71	1	71	(Eng.) 16 hrs. ($1,029); (R.K.) 4 hrs. ($151)	1,420 hrs. (1,136 Eng., 284 R.K.); $85,754 ($73,033 Eng., $10,721 R.K.)
R5, R6, R7, and R8. Each RAS-entity (TO, GO, DP)	1,595	1	1,595	(Eng.) 24 hrs. ($1,543); (R.K.) 12 hrs. ($453)	57,420 hrs. (38,280 Eng., 19,140 R.K.); $3,183,556 ($2,461,021 Eng., $722,535 R.K.)
R9. Each Reliability Coordinator	15	1	15	(Eng.) 10 hrs. ($653); (R.K.) 4 hrs. ($151)	210 hrs. (150 Eng., 60 R.K.); $11,909 ($9,644 Eng., $2,265 R.K.)
TOTAL			**3,291**		**116,770 hrs. (78,086 Eng., 38,684 R.K.); $6,480,470 ($5,020,149 Eng.; $1,460,321 R.K.)**

Title: FERC-725A (Mandatory Reliability Standards); FERC-725G (Mandatory Reliability Standards: PRC-012-2)

Action: Revision to existing collections.

OMB Control No: 1902-0244 (FERC-725A); 1902-0252 (FERC-725G)

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[42] The estimates for cost per response are derived using the following formula: Burden Hours per Response * $/hour = Cost per Response. The $64.29/hour figure for an engineer and the $37.75/hour figure for a record clerk are based on the average salary plus benefits data from the Bureau of Labor Statistics.

Respondents: Business or other for profit, and not for profit institutions.

Frequency of Responses: Annually

Necessity of the Information: Proposed Reliability Standard PRC-012-2 sets forth Requirements for remedial action schemes to ensure that remedial action schemes do not introduce unintentional or unacceptable reliability risks to the bulk electric system and are coordinated to provide the service to the system as intended.

Internal review: 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.

22. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, Office of the Executive Director, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, e-mail: DataClearance@ferc.gov, phone: (202) 502-8663, fax: (202) 273-0873].

23. Comments concerning the information collection proposed in this Notice of Proposed Rulemaking 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 FERC-725A and FERC-725G and the docket number of this Notice of Proposed Rulemaking (Docket No. RM16-20-000) in your submission.

IV. Environmental Analysis

24. 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.[43] The action proposed here falls within the categorical exclusion in the Commission's regulations for rules that are clarifying, corrective or procedural, for information gathering, analysis, and dissemination.[44]

V. Regulatory Flexibility Act

25. The Regulatory Flexibility Act of 1980 (RFA)[45] generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities.

26. The proposed Reliability Standard PRC-012-2 will apply to approximately 1681 entities in the United States. Comparison of the applicable entities with the Commission's small business data indicates that approximately 1,025 are small entities or 61 percent of the respondents affected by proposed Reliability Standard PRC-012-2.[46]

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[43] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Preambles 1986-1990 ¶ 30,783 (1987).

[44] 18 CFR 380.4(a)(2)(ii) (2016).

[45] 5 U.S.C. 601-612 (2012).

[46] 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 Notice of Proposed Rulemaking, we apply a 500 employee threshold for each affected entity. Each entity is *(continued ...)*

The Commission estimates for these small entities, proposed Reliability Standard PRC-012-2 may need to be evaluated and documented every five years with a cost of $6,322 for each evaluation. The Commission views this as a minimal economic impact for each entity. Accordingly, the Commission certifies that the proposed Reliability Standard PRC-012-2 will not have a significant economic impact on a substantial number of small entities.

VI. Comment Procedures

27. 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. RM16-20-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

28. 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.

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classified as Electric Bulk Power Transmission and Control (NAICS code 221121).

29. 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.

30. 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 below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VII. Document Availability

31. 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.

32. 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.

33. 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.

FERC Notice of Proposed Rulemaking (NOPR) Remedial Action Schemes (RAS) PRC-012-2, Docket RM-20-000

Guy V. Zito
NPCC RSC
March 8-9, 2016

FERC NOPR RAS

- **Background**
- **PRC-012-2 Remedial Action Schemes**
- **NOPR Proposed Actions and Solicitations for Comments**
- **RAS Potential Strategies**
- **Future Actions**

FERC NOPR RAS

Background

- NPCC Type I, II, III Special Protection Systems SPS
- NERC SCPS- RAS, LAPs, SPSs. Inconsistencies
- PRC-012-0- RAS/SPS, PRC-013-0 Database, PRC-014-0 Assessment "fill-in-the blank" **not** FERC approved, PRC-015-0 Data and PRC-016-0 Misops, PRC-017-0 M & T, **approved** then refiled as Version 1 standards with RAS nomenclature
- RAS Definition Approved and Effective April 1, 2017

FERC NOPR RAS

Background, continued

- NPCC SPS Database, RCC approval annually
- NPCC Directory 7 approval process for SPS
- PRC-012-2 filed August 5, 2016
  - Supersede PRC-012-1, PRC-013-1, and PRC-014-1
  - Retire PRC-015-1, PRC-016-1
- PRC-017-1 RAS Maintenance and Testing will be retired in accordance with the PRC-005-6 Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance March 31, 2017

FERC NOPR RAS

- **PRC-012-2**
  - Applicable to RC, PC, RAS Entity (TO, GO, DP – owner of RAS)
  - 9 requirements (paraphrased)
    - RAS Entity provides all information to RC
    - RC performs RAS review
    - RAS Entity will resolve all RC issues
    - PC evaluations every 5 years
    - RAS Entity evaluates operations and misops.
    - RAS Entity participate to develop CAP to RC in 6 months
    - RAS Entity implement CAP- revise and notify RC
    - RAS Entity functional test every 6/12
    - RC update database every 12 months- at a minimum

FERC NOPR RAS

- **PRC-012-2 Implementation**
  - Effective the first day of the first calendar quarter 36 months following applicable government regulatory approval or BOT approval.
  - Limited Impact-A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and is classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type III in NPCC is recognized as a limited impact RAS upon the effective date of PRC-012-2 and is subject to all applicable requirements.

FERC NOPR RAS

- **PRC-012-2 Implementation**
  – R4 (PC Evaluation of RAS) completed within 5 full calendar years following the effective date.
  – RAS (Functional Test)not designated as limited impact, initial performance of obligations under Requirement R8 must be completed at least once within six (6) full calendar years after the effective date.
  – RAS designated as “limited impact”, initial performance of obligations under Requirement R8 must be completed at least once within twelve (12) full calendar years after the effective date
  – Requirement R9 (RC Database) within twelve full calendar months after the effective date

FERC NOPR RAS

- **PRC-012-2**
  - NPCC participated in standard development
  - Promoted the concept of “limited impact”
  - Recognition that regions have processes for reviewing SPSs prior to their commissioning
  - Alignment of SPS Type 1 and 2 with RAS and Type 3 with “limited impact” to reduce disruption of mechanisms
  - Database requirements for RCs may be met through regional databases

FERC NOPR RAS

NOPR Proposed Actions

- Proposes to approve the PRC-012-2, VRFs, VSLs, Implementation Plan and Effective Dates
- Proposes approval of withdrawals and retirements

FERC NOPR RAS

NOPR Solicitations for Comments

- PRC-012-2 will not modify or supercede performance requirements in TPL-001-4
  - Table 1 non-consequential load loss may not exceed 75 MW for certain Category P1, P2, or P3 contingencies……
- PRC-012-2 processes
  - LAPS or Type III RAS will be compliant with Reliability Standard TPL-001-4 prior to the effective date of Reliability Standard PRC-012-2 wrt the 75 MW loss of load for LR RAS

FERC NOPR RAS

NOPR Solicitations for Comments, continued

- Should “limited impact RAS” be a NERC defined term and added to the NERC Glossary of Terms

FERC NOPR RAS

RAS Potential Strategy

- Remove all non-conforming RAS from SPS list
- Identify newly conforming SPS that are RAS and to be added to the list
- Seek approvals of those RAS through the TFs
- Identify Type 3 load rejection SPSs and whether the amount of load exceeds 75 MW.

FERC NOPR RAS

RAS Potential Strategy

- Notify all new RAS owners of their inclusion on the RAS list/databased
- Finalize the RAS list and approval with RCC (for compliance use)
- Revise NPCC Glossary term for SPS to indicate see NERC RAS
- Upon release of final Rule, revise NPCC documents, (e.g. Directory 7) accordingly.

FERC Order 830

- **Future Actions**
  - NPCC RAS (SPS) List revised and approved by RCC
  - Continued discussions with TFs on strategy
  - Implement conforming changes to Directories

- **Questions/Comments**

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Distributed Energy Resources

Connection Modeling and Reliability Considerations

February 2017

RELIABILITY | ACCOUNTABILITY

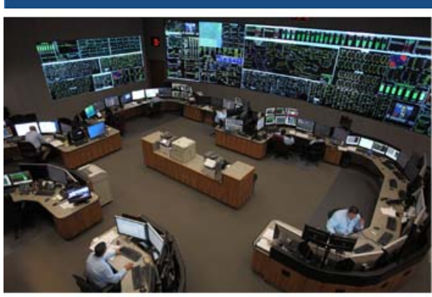


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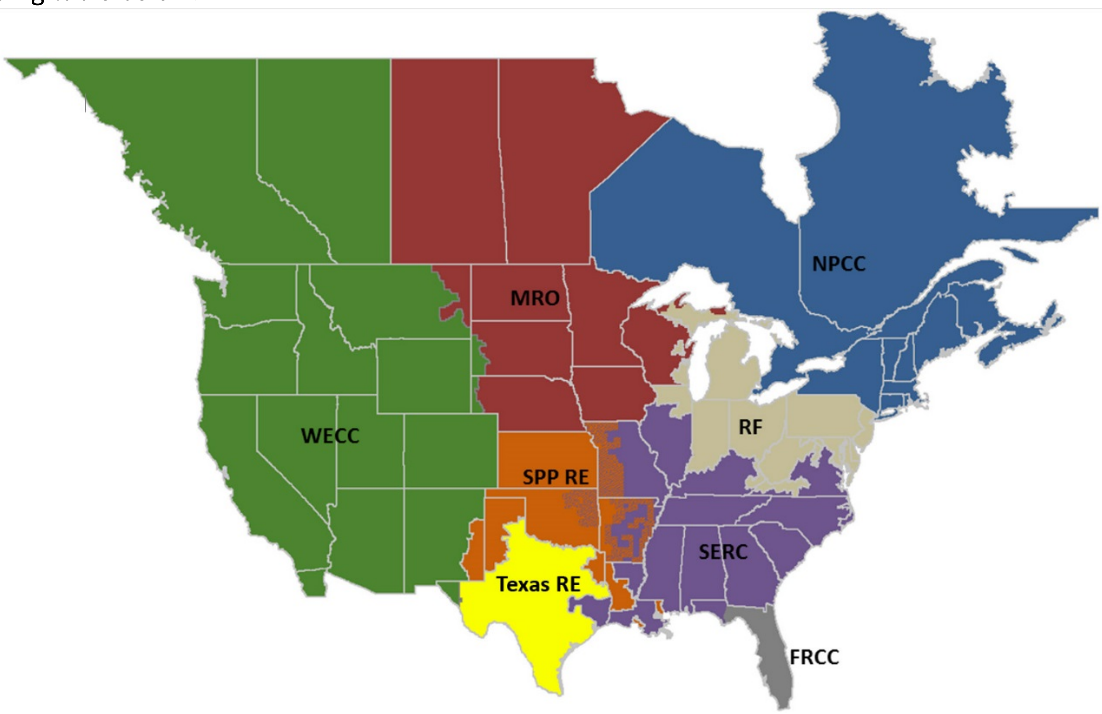
Table of Contents

Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability and security 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 Entity (RE) boundaries as shown in the map and corresponding table below.



The North American BPS is divided into eight RE boundaries. The highlighted areas denote overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

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
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

The North American electric power system is transforming to a resource mix that relies less on coal and nuclear while integrating more natural gas, wind, solar, distributed generation, and demand response resources. The NERC Essential Reliability Services Working Group (ERSWG) is studying this transformation in the broader context of monitoring grid reliability and resiliency. Additionally, as noted in the ERS Framework Report[1] in 2015, Distributed Energy Resources (DER) are a rapidly growing part of this transformation. This report discusses the potential reliability risks and mitigation approaches for increased levels of DER on the BPS.

At the distribution level, the potential impacts of DER are fairly well understood in the industry, but the translation of these impacts to the BPS has been studied less. This report discusses the challenges as well as the steps forward for reliably integrating higher DER penetrations.

In certain areas, DER are numerous and embedded within a distribution system that has traditionally been viewed as a relatively passive load resource on the BPS, but this will no longer be a valid assumption with the integration of more DER on the electric system. In addition, newer DER technologies are capable of providing advanced support services that will be needed as the transition from conventional synchronous resources to nonsynchronous inverter-based resources continues. It is paramount that NERC and the industry understand DER functionality and develop a set of guidelines to assist in modeling and assessments such that owners/operators of the BPS can evaluate and model DER in the electric system. Data requirements and information sharing across the transmission-distribution (T-D) interface should also be further evaluated to allow for adequate assessment of future DER deployments.

This report does not make an assessment of the capability of DER versus conventional resources; it is only meant to help entities, regulators, and policy makers better understand the differences between DER and conventional generation and how DER affect the BPS. DER will increasingly have state-of-the-art capabilities for active power control and reliability services. However, there are differences in how DER are deployed within the grid and the characteristics of the services and responses that they provide, so these differences must be understood and modeled appropriately. As a result, this report explains how practices for modeling and operating the BPS may be enhanced to reflect future system characteristics. Simultaneous efforts to improve DER interconnection standards, such as proposed changes to the Institute of Electrical and Electronics Engineers IEEE 1547[2], will assist in establishing criteria and requirements for interconnection of DER to electric power systems.

The ability to accurately model the power system is important given the highly complex and interconnected nature of the power grid. System modeling is critical for power grid operations and planning for both normal operations and disturbances to ensure reliable operation of the BPS. All components of the system must be represented in the models, either directly or in an aggregated way, with sufficient fidelity to enable the model to provide meaningful and accurate simulations of actual system performance. A modular approach to represent DER in BPS studies, with some level of data validation, may ensure accurate representation of the resources for the specific BPS study type. While dynamic models for different DER technologies are available, limited existing knowledge and experience of modeling DER in system planning studies and operating with higher penetration DER levels will require future collaborative research, knowledge exchange, and learning.

Even though load and DER reside "behind-the-meter" the modeling for each of these respective network elements requires a different set of data. As the penetration level of DER increases, the classical transmission model of distribution system load (netted generation and load) is not valid; the unique characteristics of DER must be modeled separately. This is distinct from tariff and ratemaking issues (e.g., net metering, time-of-use rates, value

[1] NERC Essential Reliability Services Task Force Measures Framework Report; November 2015
[2] IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems

of solar methods, etc.). Data for DER modeling and verification purposes must be collected, and the industry should determine the level of granularity which corresponds to the future BPS modeling needs.

The ERSWG has also discussed the importance of continuously maintaining the balance between demand and generation for balancing areas. These ramping and balancing activities may become more challenging for regions with high levels of DER as these activities will require resources located on the BPS as well as the distribution system, and the distribution system may not be visible to or controlled by the BPS operator.

A coordinated effort by transmission and distribution entities is needed to determine the appropriate use of future DER capabilities. Some DER have the capability to ride through disturbances, contribute reliability services, and follow dispatch signals. These capabilities are starting to be used either directly or through aggregators for a number of emerging services (e.g., demand response, micro-grids, virtual power plants, etc.). Dispatch of DER for system operations are not explicitly discussed in this report. As the capabilities of DER evolve to include advanced controls (e.g. active power control) and monitoring, the transmission and distribution utilities will need to expand their coordination activities in order to maintain BPS reliability.

Introduction

In 2015, the Essential Reliability Services Task Force (ERSTF) recognized that the North America's electric power system generation resource mix is changing from the use of larger synchronous sources to the use of a more diverse fleet of smaller sized resources with varying generation characteristics. As this transformation continues, there is a fundamental shift in the operational characteristics of the power system as a whole and hence potential reliability implications[3]. The ERSTF final report provides directional measures to help the industry understand and policy makers prepare for the on-going transition. The measures provide insight to key technical considerations that may not have represented challenges with a conventional generation fleet, but may pose risks to BPS reliability under a changing generation fleet.[4]

The growing interest in a more decentralized electric grid and new types of distributed resources further increase the variety of stakeholders and technologies. Both new and conventional stakeholders are building or planning to build distributed solar photovoltaic systems, energy management systems, micro-grids, demand services, aggregated generation behind the retail meter, and many other types of distributed generation. Many of these stakeholders have considerable experience with installing such systems on the distribution network for the benefits of industrial or residential customers; however, they may have less familiarity with the BPS and the coordinated activities that ensure system reliability during both normal operation and in response to disturbances. While this report examines reliability considerations from the viewpoint of the BPS, it will also help DER providers understand the reliability considerations for the power system as a whole.

Increasing amounts of DER can change how the distribution system interacts with the BPS and will transform the distribution system into an active source for energy and ERS. Attention must be paid to potential reliability impacts, the time frame required to address reliability concerns, coordination of ERS and system protection considerations for both the transmission and distribution system, and the growing importance of information sharing across the transmission-distribution (T-D) interface.

Today, the effect of aggregated DER is not fully represented in BPS models and operating tools. This could result in unanticipated power flows and increased demand forecast errors. An unexpected loss of aggregated DER could also cause frequency and voltage instability at sufficient DER penetrations. Variable output from DER can contribute to ramping and system balancing challenges for system operators whom typically do not have control or observability of the DER within the BPS.

These issues present challenges for both the operational and planning functions of the BPS. In certain areas, DER are being connected on the distribution system at a rapid pace, sometimes with limited coordination between distribution utilities and BPS planning activities. With the rapid rate of DER installations on distribution systems, it will be necessary for the BPS planning functions to incorporate future DER projections in BPS models. These changes will affect not just the flow of power but also the behavior of the system during disturbances. It is important to coordinate the planning, installation, and operation of DER with the BPS.

In this report the formal definition for DER is provided first, followed by BPS reliability considerations, modeling, and DER ride-through response given an event grid disturbance. Subsequently, the report provides a list of NERC reports and standards that address or may be affected by DER, followed by the recommendations and summary. Supplemental appendices are provided and an appendix will discuss operational considerations of DER.

[3] December 2015 – Essential Reliability Services Abstract Report
[4] 2015 Essential Reliability Services Task Force Framework: Measure 10

The transformation of the distribution utility has become a major topic of discussion in the industry. It will be important for NERC’s ERS effort to follow this transformation and consider the implications and responsibilities for ensuring reliability with higher DER penetrations.

Chapter 1: Definition of Distributed Energy Resources

NERC recognizes that various definitions have been used within the industry; however, it is important to establish a working definition to create the context for the discussions within this report. Here, DER is defined as:

> A Distributed Energy Resource (DER) is any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Electric System (BES).

As developed by NERC and approved by FERC, the BES definition includes all the larger elements and facilities that are necessary for the reliable operation and planning of the interconnected bulk power system (BPS). With the growing prevalence of DER, some areas are recognizing that the locations and characteristics of the DER devices must be correctly represented in planning, operating, and stability models to achieve accurate results. Understanding DER is therefore becoming an important consideration for BPS reliability.

There are various types of DER, a list of selected DER types and their respective definitions are provided below. The definitions do not provide a comprehensive review of industry terms, however they represent a framework for moving forward with an improved understanding of the role of DER in the context of BPS reliability.

DER include any non-BES resource (e.g. generating unit, multiple generating units at a single location, energy storage facility, micro-grid, etc.) located solely within the boundary of any distribution utility, Distribution Provider, or Distribution Provider-UFLS Only, including the following:

- **Distribution Generation (DG)**: Any non-BES generating unit or multiple generating units at a single location owned and/or operated by 1) the distribution utility, or 2) a merchant entity.
- **Behind The Meter Generation (BTMG):** A generating unit or multiple generating units at a single location (regardless of ownership), of any nameplate size, on the customer's side of the retail meter that serve all or part of the customer's retail load with electric energy. All electrical equipment from and including the generation set up to the metering point is considered to be behind the meter. This definition does not include BTMG resources that are directly interconnected to BES transmission.
- **Energy Storage Facility (ES):** An energy storage device or multiple devices at a single location (regardless of ownership), on either the utility side or the customer's side of the retail meter. May be any of various technology types, including electric vehicle (EV) charging stations.
- **DER aggregation (DERA):** A virtual resource formed by aggregating multiple DG, BTMG, or ES devices at different points of interconnection on the distribution system. The BES may model a DERA as a single resource at its "virtual" point of interconnection at a particular T-D interface even though individual DER comprising the DERA may be located at multiple T-D interfaces.
- **Micro-grid (MG):** An aggregation of multiple DER types behind the customer meter at a single point of interconnection that has the capability to island. May range in size and complexity from a single "smart" building to a larger system such as a university campus or industrial/commercial park.
- **Cogeneration:**[5] Production of electricity from steam, heat, or other forms of energy produced as a by-product of another process.

[5] NERC Glossary of Terms

- **Emergency, Stand-by, or Back-Up generation (BUG):** A generating unit, regardless of size, that serves in times of emergency at locations and by providing the customer or distribution system needs. This definition only applies to resources on the utility side of the customer retail meter.

While defining DER is an important first step, to fully understand the potential interaction of these resources with the BPS, it is essential to recognize how these resources are interconnected to the power grid. DER, as defined above, are generally interconnected to a distribution provider's electric system at the primary voltage (≤ 100 kV but > 1 kV) and/or secondary voltage (≤ 1 kV). As such, the effect of aggregated DER is not fully represented in BPS models and operating tools. A discussion and examples of the types of interconnections between DER and the BPS are provided in Appendix A. Understanding how these resources are defined by NERC and how they are interconnected to the BPS allows for further exploratory discussions on how to model DER and their current operating characteristics.

For the purposes of this report, DER are defined as resources that produce electricity. Demand side management (DSM) resources which do not produce electricity are not included in the definition and is outside the framework of this report. As shown in Appendix D, while DSM activities may not have the same characteristics or behaviors as resources that produce electricity, DSM activities can have impacts at the T-D interface that overlap and interact with those of DER. As such, the task force recommends future consideration of DSM in the DER definition and how the recommendations of this report may be applied to DER and DSM resources in a unified way.

Chapter 2: Reliability Considerations for DER

In certain areas, North America is experiencing a growing interest in a more decentralized electric grid with increasing penetrations of DER. Greater levels of these interconnected resources reinforce the need to ensure the reliability of the BPS during both normal operation and in response to disturbances. Increasing amounts of DER can change how the distribution system interacts with the BPS and may transform distribution utilities into active sources for both energy and ERS. These dramatic changes for the distribution system, which can alter not just the flow of power but also the responses to various types of disturbances, must be understood and represented in the planning and operation of the grid. This can be accomplished through coordinated activities that ensure effective communication is occurring between those operating the BPS and the distribution provider.

The following is an overview of the key areas of focus on which the DERTF has collaborated:

- **Modeling:** DER are typically netted with load at the distribution bus for operations and planning. The challenge is to understand their variability and interactions with other resources. The electric industry has studied and incorporated the characteristics of conventional resources into the models that are used for planning and operations. To support the reliable integration of DER at higher levels, appropriate modeling methods will be necessary.
- **Ramping and Variability:** Certain types of DER create significant ramps, such as morning and evening solar ramps that are different than historically experienced by the distribution system and the BPS. Coordination between BPS and distribution system for planning, installation, and operation of DER resources is a continuing need as the generation resource mix evolves on both transmission and distribution systems
- **Reactive Power:** Currently, most DER are not required to provide reactive support to help control local voltage levels. Modern technologies, including inverters for new rooftop solar PV installations, should have the capability to support voltage and ride-through voltage excursions. Use of these capabilities will be increasingly important to support the reliability of both the transmission and distribution systems.
- **Frequency Ride-Through:** DER are not coordinated with the voltage and frequency ride-through requirements of *NERC Standard PRC-024-2*. As DER are added to the system, frequency and voltage ride-through capabilities become important and must be considered both locally and for the BPS.
- **System Protection:** DER are not coordinated with UFLS programs nor are they used to calculate the most severe single contingency and contingency reserve requirements. High levels of DER with inverters can also result in a decline in short circuit current, which can make it more difficult for protection devices to detect and clear system faults. Hence, the implications of DER as part of system protection must be taken into consideration while planning the BPS and distribution systems.
- **Visibility and Control:** Many DER are passive in that they do not follow to a dispatch signal and are generally not visible to the system operator. The lack of visibility and control is not only a challenge for operations, but must also be accounted for in the planning of the BPS. At higher penetration levels, DER capabilities related to visibility and control may become increasingly important.
- **Load and Generation Forecasting:** Currently, DER are modeled as load modifiers for most load forecasting tools. However, given the number of DER installation applications and projections of future growth, it may become important to have sufficient information to support forecasting of DER power production separately from load, as well as to consider future DER deployment scenarios in the planning of both the distribution systems and the load/generation forecasting systems.
- **Interconnection Requirements:** Interconnection requirements are evolving with increasing DER penetrations, and as a consequence of this, a number of DER classes with very different dynamic behaviors

will exist in the BPS. It will be important to know this information, at least in an aggregate way, so that the dynamic characteristics can be modeled correctly for BPS planning.

- **Reliability Standards:** NERC and industry must consider the existing standards, functional model, and related equipment standards in terms of accommodating the growing integration of DER while ensuring prudent planning and reliable operation of the BPS.

DER and Potential Risks to Reliability

At low penetration levels, the effects of DER may not present a risk to BPS reliability; however, as penetrations increase, the effect of these resources can present certain reliability challenges that require attention. This leads to areas where further consideration is needed to better understand the impacts and how those effects can be included in planning and operations of the BPS.

The data on installed and projected DER units is needed for reliability modeling purposes. Important data for modeling include information on the location, type, size, configuration, interconnection characteristics, disturbance response characteristics, and date of operation of the equipment. DER generation profiles would also improve the fidelity of modeling results rather than forcing models to assume worst-case scenarios. It is particularly important that both data and models be available down to the elements of interest to the models (e.g., separating the DER generation from the load).

Maintaining the balance between demand and generation for a BA is required. If balance is not maintained, then there is not enough supply of generation to meet the load demand. Additionally, ramping is a concern for a BA because ramping may cause the BA to rely on its neighbors for capacity resources when there is a sudden large increase or decrease in generation. Ramping and balancing activities may become more challenging for regions with high levels of DER and variable energy resources (VER). Utility-scale VER (e.g., solar and wind) are now required to ride through disturbances, to provide reliability services, and to have active power management capability to respond to dispatch or automatic generation control (AGC) signals. Many DER will also have such capabilities, and these capabilities may be used either directly or through aggregators for numerous emerging services (e.g., demand response, micro-grids, virtual power plants, etc.).

System operators require sufficient levels of ERS, from on-line resources, for the reliable operation of the BPS. It is not necessary that all resources provide all services at all times, but if conventional resources are off-line or replaced by DER, it may be increasingly important to use DER for active power control and ERS. The DER task force is not suggesting that DER be dispatched like conventional generators or utility-scale VER power plants, but methods to obtain active power control and reliability services from some portion of DER are likely to be important in the future.

Current work (i.e. [43]) on enhancements to the IEEE 1547 interconnection requirements and how capabilities of DER are used will present opportunities for improving BPS reliability. Technology advances have the potential to alter DER from a passive “do no harm” resource to an active “support reliability” resource. From a technological perspective, modern DER units will be capable of providing ERS and supporting BPS reliability. These technologies are likely to become more widely available in the near future, and they present an opportunity to enhance BPS performance when applied in a thoughtful and practical manner. For example:

- When viewed in aggregate, multiple DER units can scale up to become a very large resource. For example, in 2016, California Independent System Operator (CAISO) stated there are 4,900 MW of DER in its Balancing Authority. This was its largest single resource when aggregated. If DER could provide frequency response on a 5% droop characteristic, it could provide 163 MW / -0.10 Hz of frequency response to CAISO. This is a significant benefit.

- With respect to voltage support, active voltage control on a feeder circuit could significantly lower the risk of fault induced delayed voltage recovery (FIDVR) events for multiphase faults on the transmission system. By reducing net load on the feeder and providing voltage support, these events related to locked rotor current of single-phase compressors following a fault would have a reduced effect on the distribution voltage and BPS voltage levels.
- With the possible aggregation of DER capabilities, it becomes feasible to “dispatch” DER for system balancing, demand response, operating and contingency reserves, or to mitigate ramp rate concerns in the morning and evening.

The capabilities of VER are evolving rapidly, so there are a number of emerging topics that are not within the scope of this report. For example, protection settings are a future step in the modeling efforts that are discussed in Chapter 3, and IEEE 1547 proposals currently deal with reenergizing but not with DER capabilities for use as a black start resource. NERC should continue to monitor and participate in the ongoing evolution of capabilities and how such capabilities should be incorporated into future planning and operating of the BPS.

Chapter 3: Data and Modeling for DER

The increasing amount of DER connected to the distribution system requires consideration of DER resources in the planning and operations of the BPS. A key takeaway for both planning and operating considerations is the collection and sharing of data across the transmission-distribution (T-D) interface.

The scope of this chapter covers the recommended data requirements followed by the details around appropriate modeling for 1) steady-state power flow and short-circuit studies, and 2) dynamic disturbance ride-through and transient stability studies for BPS planning. Distribution system aspects (e.g., distribution protection and planning), BPS small-signal stability, and BPS operational aspects which include flexibility and ramping are out of the scope of this document.

Data Requirements and Information Sharing at the T-D Interface

With DER being connected at the distribution level but having potential impact at the BPS level, the following data and information sharing recommendations, across the T-D interface, are important to support adequate modeling and assessment of BPS reliability issues:

- Each substation with aggregated DER data represents the mix of DER and their capabilities. Examples of DER data categories include the following:
  - DER type (i.e., PV, wind, cogeneration, etc.)
  - DER MVA rating
  - Relevant energy production characteristics (i.e., active tracking, fixed tilt, energy storage characteristics, etc.)
  - DER operating power factor and/or reactive and real power control functionality
    - DER point of common coupling (PCC) voltage
  - DER location: behind the meter/in front of the meter
  - Date that DER went into operation
- A set of default equivalent impedances for various distribution grid types that can be used to choose adequate parameters (e.g., WECC's PVD1 model for distributed PV systems)
- Relevant interconnection performance requirements based on national or regional standards
- DER stability models and their voltage and frequency trip parameters. In particular the regionally specific parameters Vt0, Vt1, Vt2, and Vt3 of WECC's distributed PV model (*PVD1*) [41]

The recommended data requirements should be considered by the regional committees and specified in regional criterion such as WECC's "Steady State and Dynamic Data Requirements MOD-(11 and 13)-WECC-CRT-1 Regional Criterion" [5] and others.

DER Modeling for Bulk Power System Planning and Operations

While it may be desirable to model DER in all planning studies and in full detail, the additional effort of doing so may only be justified if DER are expected to have significant impact on the modeling results. An assessment of the expected impact will have to be scenario-based, and the time horizon of interest may vary between study types. For long-term planning studies, expected DER deployment levels looking 5–10 years ahead may reasonably be considered. Whether DER are modeled in BPS studies or not, it is recommended that the minimum data collection of DER interconnections be established in order to adequately assess future DER deployments.

Modeling modern bulk systems with a detailed representation of a large number of DER and distribution feeders can increase the complexity, dimension, and handling of the system models beyond practical limits in terms of computational time, operability, and data availability. Therefore, a certain degree of simplification may be needed either by model aggregation (i.e., clustering of models with similar performance), by derivation of equivalent models (i.e., reduced-order representation), or by a combination of the two. Netting of DER with loads at the substation level is not recommended for high-DER penetration scenarios because the resulting models will misrepresent potential aggregate impacts of DER on BPS power flows and dynamic performance.

A *modular approach* to represent DER in BPS studies as illustrated in Figure 3.1: Modular Representation of DER in BPS Steady-State and Dynamic Studies [1, 2]. Figure 3.1 is recommended to ensure accurate representation of the resources for the specific BPS study type. The hierarchy of the clustering of DER for model aggregation could consider:

- Differentiation of DER per resource type to derive meaningful dispatch scenarios rather than worst-case dispatches for BPS planning studies.
- Differentiation of DER per interconnection requirements performance (i.e., the adhering interconnection standard requirements) to represent the fundamentally different steady-state and dynamic behavior among future and legacy DER.
- Differentiation of DER per technology-type (e.g., inverter-coupled versus directly-coupled synchronous generator DER) to accurately represent the technology-specific dynamic behavior.

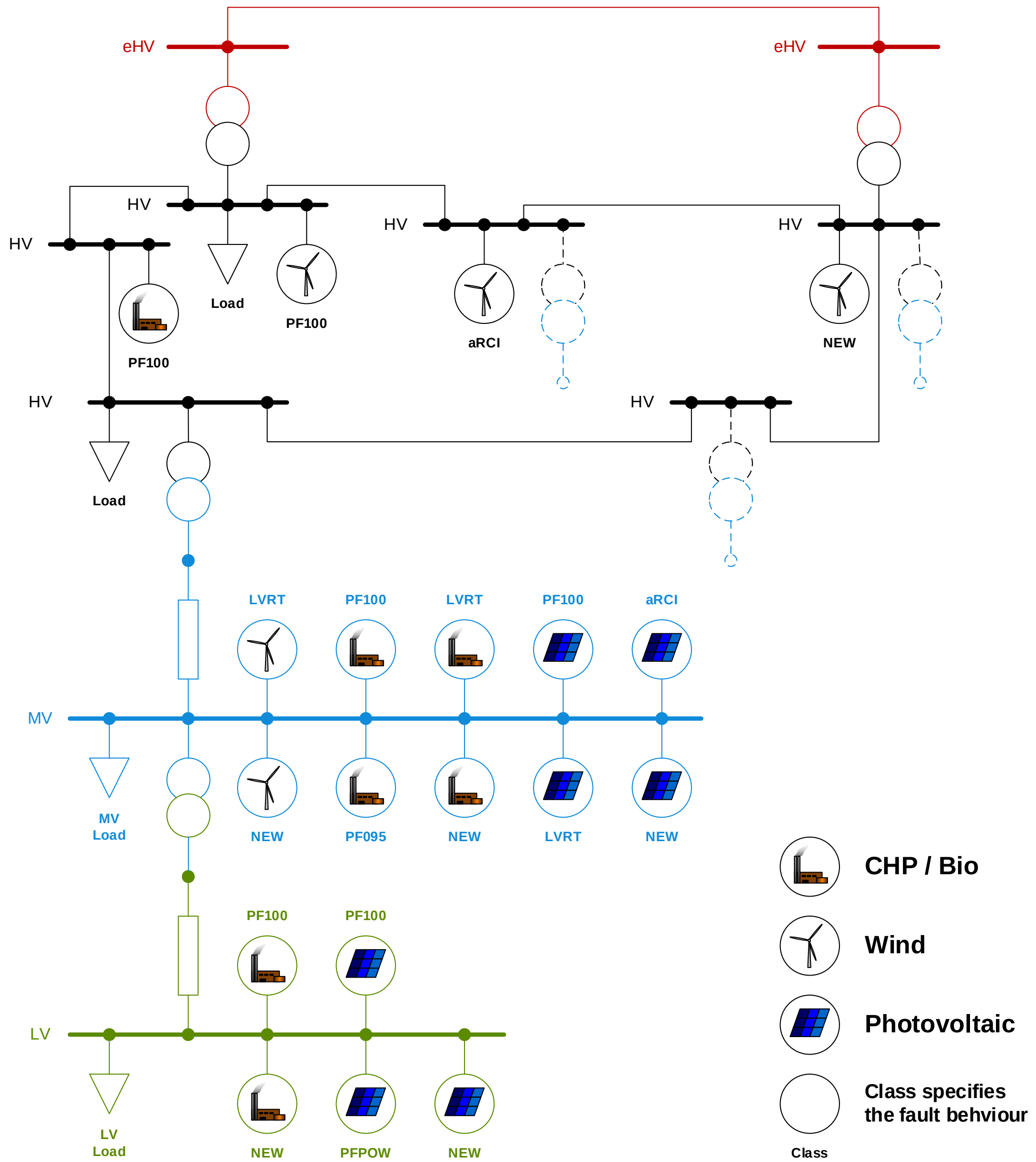


Figure 3.1: Modular Representation of DER in BPS Steady-State and Dynamic Studies [1, 2]

Defining the appropriate balance between model accuracy and simplicity of steady-state and dynamic equivalent models for DER is a major objective of ongoing research efforts. However, certain guidelines for DER modeling have been published. The following includes a synopsis of the industry guidelines issued by the Western Electricity Coordinating Council (WECC). Aggregated and/or equivalent modeling of DER is discussed for four types of bulk power system planning studies:

- Steady-state power flow studies
- Steady-state short-circuit studies
- Dynamic disturbance ride-through studies
- Dynamic transient stability studies

Data requirements were summarized at the start of this chapter. The limited existing knowledge and experience on modeling DER in BPS planning studies will require ongoing research, knowledge exchange, and learning.

Steady-State Studies

Steady-state studies aim at:

- Power flow calculation to determine BPS real and reactive power flows for network expansion planning, voltage stability studies and coordination of voltage controls at the T-D interface
- Short-circuit calculations to determine short-circuit power levels for equipment rating and voltage sag propagation analysis

Modeling of DER in these studies would consider the real-power injection at distribution system level and the reactive power that may be supported or required by DER. A power flow case is needed to initialize the state variables of a dynamic BPS model for a dynamic stability study.

Steady-State DER Models

Appropriate DER models are required and may differ between steady-state analyses:

- Steady-state power flow calculations may only require a standard generator or simplistic voltage or current source models with voltage control loops appropriate for steady-state analysis under normal conditions of voltage and frequency.
- Steady-state short-circuit studies require appropriate DER models that would adequately represent the short-circuit contribution from DER. Inverter-based DER are current and power limited sources. A current-limited Norton equivalent with control loops that adequately model the response under abnormal conditions of voltage is required. The short-circuit contribution of DER depends significantly on the performance specified by interconnection requirements, such as trip and ride-through requirements. Traditional steady-state short-circuit analysis algorithms are not suitable for inverter-based DER. New algorithms that iteratively calculate the current-limited short-circuit contributions from inverter-based DER may be needed.

Aggregated Modeling and Netting of DER with Load

In most existing BPS planning studies, the distribution system load is aggregated at the transmission buses and netted with generation on the distribution system (DER generation is treated as negative load). In study cases and grid areas where DER levels are expected to significantly impact power flows between the transmission and distribution system to the point that they may conflict with NERC system performance criteria (e.g., NERC TPL-001-4 [3]), DER should not be netted with load but modeled in an aggregated and/or equivalent way to reflect their dynamic characteristics and steady-state output. Exceptions for permissive netting of DER (not explicitly modeling DER but reducing load by DER generation based on explicitly available DER data) may be acceptable in steady-state studies for those DER that inject real power only at unity power factor without the ability of providing static voltage support at low DER penetration levels.

Depending on the study region, the aggregate DER penetration at substation level, regional level, or interconnection-wide level may give indication towards the expected impact of DER on the system performance; however, the decision to aggregate DER must always be system-dependent. This assessment should be irrespective of whether it is behind-the-meter DER or before-the-meter (utility-scale) merchant DER.

Future modeling may require DER to be modeled distinctively from the load. Thresholds for aggregating DER or distinctly modeling DER may be determined by an area's specific needs. An example of a modeling threshold in order to limit overall BPS model complexity is provided by the WECC manual [4, 5]. The WECC manual [4, 5] requires:

- Modeling of any single DER with a capacity of greater than or equal to 10 MVA explicitly, and

- Modeling of multiple DER at any load bus where their aggregated capacity at the 66/69 kV substation level is greater than or equal to 20 MVA with a single-unit behind a single equivalent (distribution) impedance model as shown in Figure 3.2 based on WECC's "PV Power Plant Dynamic Modeling Guide" [6].

The threshold above which DER are not netted with loads is system-specific and may depend on the study specifications, DER penetration level, and load composition. For example, in the regional case of WECC, earlier versions of the WECC Data Preparation Manual stated that a maximum amount of five percent netted generation of an area's total generation is recommended, but this statement was removed in the new version of the manual for use in 2017 [4]. In general, netting of DER with loads should be avoided.

Minimum data collection for DER modeling should be established to enable adequate assessment of future DER deployments. Related data requirements are outlined in WECC's "Steady State and Dynamic Data Requirements MOD-(11 and 13)-WECC-CRT-1 Regional Criterion" [5].

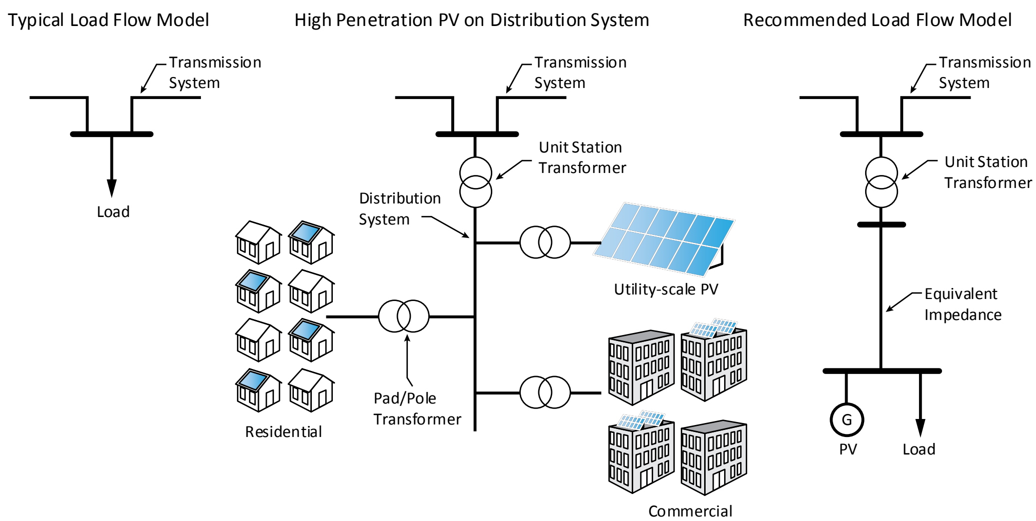


Figure 3.2: WECC Recommended Power Flow Representation for Study of High-Penetration PV Scenarios. Source: EPRI Figure Based on [6]

More Detailed Representation in Special Cases

The objective of modeling of DER for power flow studies is to capture the effect of reactive power support as well as the voltage dependent characteristics of DER in steady-state and dynamic simulations, particularly for voltage stability studies. The aggregation of DER behind a *single* equivalent distribution impedance may be insufficient for steady-state studies in special cases.

The following special conditions may require detailed representation of the distribution system, either through considering the *multiple* equivalent impedances of High Voltage to sub-transmission lines as well as Medium Voltage to primary and Low Voltage to secondary feeders separately [2] or through equivalent voltage control blocks in the equivalent DER generator model:

- Impactful penetrations of DER generation that operate at power factors other than unity and/or implement other real or reactive power functionality dependent on system voltages or power flows.
- Impactful DER penetrations in terms of their percentage of instantaneous interconnection-wide load.
- A significant amount of reverse power flows from distribution substation to BPS level.
- Substantial amounts of DER connected at different voltage levels in a region.

Depending on the particular characteristics of the distribution systems and their level of uniformity in the study case, regionally-specific equivalent impedances and equivalent voltage control blocks in the equivalent DER generator model may be used (e.g., for urban, sub-urban and rural feeders) to accurately model the voltage at the equivalent DER model terminals.

In grid regions where DER performance requirements are *changing* (i.e., have been changed or are expected to change substantially in the future), *multiple* equivalent generators may be used for each DER generation in order to appropriately reflect the DER performance. Existing DER units (i.e., legacy DER) are typically not upgraded to meet the latest performance requirements.

Dynamic Studies

Dynamic simulation studies aim at:

- Disturbance ride-through analysis to determine BPS frequency and voltage stability following normally-cleared or delayed-cleared transmission faults with consideration of the amount of DER power that may be tripped off-line during the disturbance due to under-voltage, over-voltage, under-frequency, and/or over-frequency protection.
- Transient stability analysis to determine BPS transient stability during and following normally-cleared or delayed-cleared transmission faults with consideration of fast reactive support from DER that may improve the transient response of the overall system.

Modeling of DER in dynamic BPS studies requires a solid understanding of DER performance based on both interconnection requirements and technology-specific DER performance and control systems.

Interconnection Requirements

Interconnection requirements (also known as performance requirements) are differentiated by DER rated capacity in North America and by DER connection voltage level in Europe. For BPS stability studies, interconnection requirements determine a *performance framework* for the network fault response of individual DER units depending on their commissioning period, connection level or size, and sometimes technology type.

With regard to disturbance ride-through requirements, IEEE Std. 1547-2003 [7], FERC's SGIP/SGIA [8, 9], and the former CA Rule 21 [10] for North America and California in particular, have focused on distribution-level protection and safety centric requirements meant to quickly trip DER off-line as to not interfere with legacy distribution-level protection equipment and to avoid the formation of utility islands. These standards, procedures and state rules have been or are currently being revised for voltage and frequency ride-through [11, 12, 13, 14] with a focus on providing BPS level ride-through support. Additional dynamic performance requirements for DER, such as dynamic voltage support during and/or following network faults, may evolve in the future similar to the requirements for an additional reactive current injection during faults for Germany [15, 16].

Dynamic DER Models

With respect to wind and PV generation connected to the BPS (i.e., typically wind and PV power plants of 10 MVA or larger), the following state-of-the-art generic dynamic models exist:

- **Wind:** The WECC generic wind turbine generator model (primarily for use with BPS connected wind turbine generators, but could be used for DER where detailed distribution models are developed) are documented [17]. The IEC models are documented in IEC Standard 61400-27-1 [18]. It is noteworthy that differences do exist between the generic wind turbine generator models specified in the IEC standard and the WECC modeling guidelines. The IEC models include a more detailed representation of the dynamic performance of wind turbine generators during the fault period than the WECC models [19, 20, 21] and, therefore, seem to be more suitable for transient stability studies.

- **Photovoltaic (PV):** The first generation of generic models for PV plants, developed by the WECC Renewable Energy Modeling Task Force (REMTF), has been approved under the WECC Modeling and Validation Working Group [6, 22, 23]. These models can potentially be used for modeling DER for situations where explicit detailed modeling of DER is warranted. For the purposes of BPS studies, much of the distribution system and the DER are represented as aggregated models. WECC has initiated and developed some aggregated, and simplified, DER models for representing devices such as distributed PV [6]; however, discussions continue within the WECC REMTF to improve these models. Currently, there is no IEC standard on PV modeling.
- **Synchronous Generator DER:** Modeling of large-scale directly-coupled synchronous generator (SG) and their excitation systems in power system stability studies is well established and widely accepted recommendations exist [24, 25]. Modeling of medium- to small-scale, low-inertia, distributed combined heat and power (CHP) plants is a less investigated field, although some older publications exist [26, 27, 28]. A relevant publication from recent years models the network fault response of a medium-scale diesel-driven synchronous generator [29].
- **Other Electronically-Connected Resources:** Other nonsynchronous resources, such as battery storage or voltage converter HVDC, may initially be represented by a generic inverter model if more specific models are not available.

Aggregated Modeling and Determining Dynamic Equivalence

Modeling of DER in dynamic BPS planning studies may require a certain degree of simplification to limit the data and computational requirements as well as the general handling of the BPS model. Model reduction could either be achieved by model aggregation (i.e., clustering of models with similar performance), by derivation of equivalent models (i.e., reduced-order representation), or by a combination of the two. However, equivalent models for DER should have sufficient fidelity to accurately consider the following two main challenges:

- Non-uniform model parameters of the controllers of the various DER in a distribution feeder, and;
- Considerable diversity of the terminal voltages of DER connected at different locations of a distribution feeder.

With regard to spreading model parameters, the modeling should distinguish the DER performance mandated by interconnection requirements. This could either be achieved by using separate classes of DER models with each representing the amount of DER that went into operation when certain requirements were in place, or by equivalent modeling of a mixed population of “legacy” and “modern” DER with a “partial tripping” design parameter as it has been considered in WECC’s distributed PV (*PVD1)* model [6]. Consideration should also be given to regional under frequency load shedding (UFLS) and under voltage load shedding (UVLS) programs that may trip distribution feeders at the substation level and thereby supersede DER ride-through or trip settings.

Consideration for the diversity of the terminal voltages of DER connected at different locations of a distribution feeder will be important to accurately model the dynamic response of DER in the periphery region (annulus) of a voltage sag as illustrated in Figure 3.3 [2]. This is the area where the modeling accuracy of DER may have a large impact on the simulation results in very high DER penetration studies because of the following:

- The annulus of the voltage sag can have a very large geographic extent.
- The number of DER units in this part of the system can become a significant part of the total number of regionally located DER units.
- Depending on the real and reactive power injection of DER during fault ride-through operation based on the interconnection requirements, DER can significantly influence the distribution system voltage and therefore the behavior of other DER, legacy and otherwise.

As illustrated in Figure 3.3 the post-fault real power imbalance due to under-voltage tripping of DER will be larger in the case shown in diagram (a) than in the case shown in diagram (b).The change in the area Figure 3.3 is an example of how accurately modeling DER generation may change what resources trip during a disturbance.

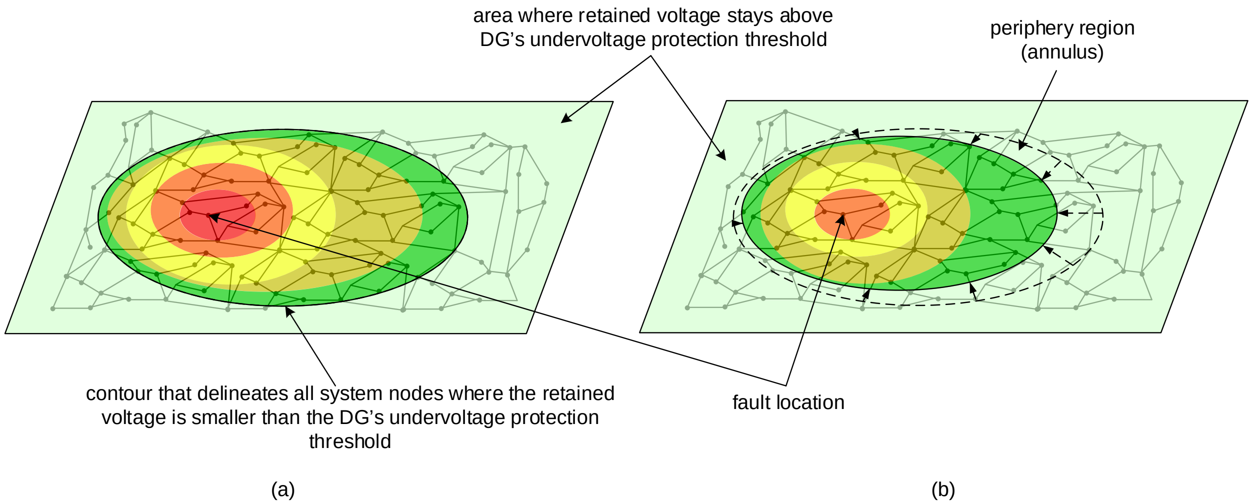


Figure 3.3: Illustration of the Area Where Modeling Accuracy of DER is Critical [2]

Until a few years ago, very little research has been published on stability models' dynamic equivalence for active distribution systems (ADS) that comprise significant amounts of DER [30]. Publication [31] summarizes the state-of-the art for the application of dynamic equivalencing methods to derive aggregated models of ADS.

Recently, a consensus is evolving that *grey box modeling* is recommended for equivalent modeling of ADS when sufficient physical knowledge is available. A grey box modeling approach is based on physical understanding of the structure and composition of the distribution system for which equivalent is being developed. System identification techniques are then used to identify model parameters based on measurements at the point of common coupling with the BPS (the boundary bus between the studied system and the system for which the equivalent is being developed). The computational challenges are reduced and these composite models can be easily integrated in dynamic simulation tools.

Notable former publications include NREL's *analytical method* of equivalencing the collector system of large wind power plants for steady-state studies [32], a generic dynamic model of an active distribution system for BPS stability studies [33, 34], and WECC's dynamic *reduced-order stability model* of DER in distribution systems considering partial loss of DER in-feed described below [6, 35].

WECC's simplified distributed PV model (*PVD1* [6, 36]) is currently not widely applied and may require further refinement. However, WECC's proposed simplified equivalent model for distributed PV systems (*PVD1*) behind a single equivalent distribution feeder impedance (Figure 3.4) can currently be regarded as the "best-in-class" reduced-order modeling approach for practical power system studies. This model is described in WECC's "PV Power Plant Dynamic Modeling Guide" [6] and is similar to the model described in [35] for the first time.

WECC's Simplified Equivalent Model for Distributed PV (PVD1)

WECC's simplified equivalent model for distributed PV systems (*PVD1*) is a highly reduced, almost algebraic, model to represent distributed PV systems in BPS stability studies. It includes active power control, reactive power control, and protective functions [36] and can account for partial tripping of distribution connected PV systems without the need to represent the distribution feeders explicitly; it can also consider the evolving mix of DER with and without ride-through capabilities, hence beyond default settings in IEEE Std. 1547-2003 [7]. The model structure of PVD1 is shown in Figure 3.4.

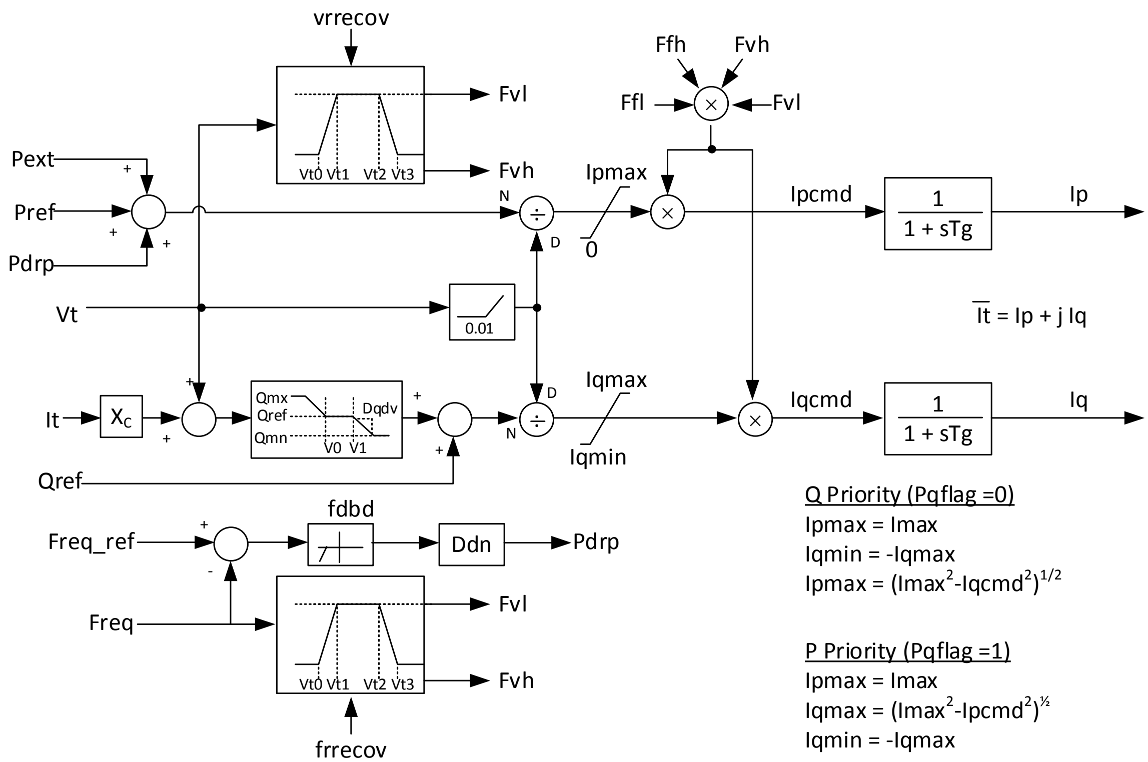


Figure 3.4: WECC Distributed PV Model Block Diagram. Source: EPRI Figure Based on [37]

An indicative verification and analysis of the accuracy of the *PVD1* model has been conducted by Electric Power Research Institute (EPRI) [38], including a comparison of modeling results with a more detailed DER aggregation technique that was proposed [2]. It was shown that the *PVD1* model accurately represents the amount of tripped DER power in the post-fault period as long as "dynamic voltage support" from soon-to-be connected DER is neglected. The *PVD1* model simplifies the DER dynamics that occur during the fault period significantly by assuming "momentary cessation" (a pause at zero power, but remaining on-line) of DER that ride through faults; this could potentially overestimate the amount of partial DER tripping. Neither does the *PVD1* model represent the delay of the protection functions. Overall, the *PVD1* model tends to produce conservative results because it tends to suggest a greater loss of DER generation than would likely be seen in the real system being simulated.

With the current limitations of WECC's *PVD1* model to represent dynamics during the fault period, the *PVD1* model may not be suitable for this type of study. The use of detailed generic DER models used for utility-scale DER (larger than 10 MVA) is recommended.

WECC's Composite Load Model with Distributed PV (CMPLDWG)

Besides modeling of DER, proper representation of load is important, especially in terms of voltage dependency [39]. Figure 3.5 illustrates WECC's Composite Load Model (named CMPLDWG) [40] with distributed PV. The PVD1 model is currently integrated into this model in a fixed way that limits the flexible use of the model. However, a modular approach will become available in the near future.

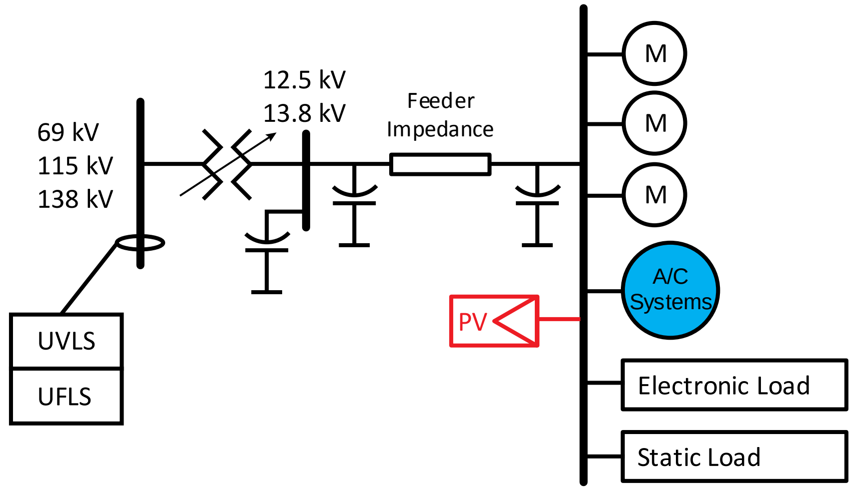


Figure 3.5: Distributed PV Model Block Diagram. Source: EPRI Figure Based on [40]

A study of the combined WECC Composite Load model (CMPLDWG) and PVD1 models was undertaken by NREL [42] and included a comparison of the combined models results and detailed distribution-level analysis of various substation-level voltage sags in order to determine the amount of DER that would trip off-line if interconnected under the IEEE 1547-2003 standard. Tuning the CMPLDWG and PVD1 model parameters resulted in close agreement of the amounts of DER that would trip off-line for a given voltage sag magnitude. However, the tuned model parameters did not match expected physical model parameters for the distribution circuit models and the functionality of the modeled PV systems (i.e. agreement between models and analysis was poor when the CMPLDWG and PVD1 models were populated with expected physical model parameters). This study indicated that either the voltage diversity of a distribution circuit cannot be sufficiently modeled using the CMPLDWG and PVD1 models or some modifications to the expected model inputs, currently based on physical/functional parameters, is required for tuning the combined models.

Chapter 4: Characteristics of Nonsynchronous DER

Background

To determine how DER may interact with the power grid, it is necessary to understand how these resources operate. DER operating characteristics are determined by the generating technology employed. Synchronous machines operate as conventional generators from a performance perspective, and these characteristics are well understood by the industry. Nonsynchronous generation technologies, such as solar photovoltaic or fuel cell resources, rely on their direct current (DC) to alternating current (AC) inverter technology to delivery energy to an AC system. DC to AC inverter electrical performance requirements are designed to protect the user (public) and the inverter equipment from electrical hazards as well as to offer capabilities necessary for the reliable operation of the power grid to which the nonsynchronous generators are connected. The commonly adopted governing requirements today are Underwriters Laboratory (UL) 1741 (2010) and (IEEE)'s 1547-2003.

UL 1741 is a product safety standard and primarily covers the hazard component of the inverter function. UL standards generally address electrical, fire, and mechanical hazards in addition to verification of electrical ratings. Additionally, UL 1741 reflects the interconnection performance requirements of IEEE 1547.1.

IEEE 1547-2003 is a standard for interconnecting DER with the power grid, and the associated requirements apply to the point of common coupling (PCC) between the grid and the DER. These requirements address technical specifications and performance requirements for the inverter including voltage and frequency ride-through, voltage regulation, response to abnormal conditions, reclosing coordination, power quality, and islanding, among other issues. IEEE 1547-2003 specifically prohibits the DER from regulating voltage at the PCC. In addition, compliant devices do not regulate frequency at the PCC, and they cannot energize the local grid when islanded.

An amendment to IEEE 1547-2003 was made denoted as IEEE 1547a [43]. This amendment specifically allowed voltage regulation at the PCC and widened voltage and frequency operation ranges to accommodate voltage and frequency ride-through requirements desired by some utilities. The ongoing full revision of IEEE 1547 will "set the stage" for DER to provide additional reliability services. Equipment meeting these proposed specifications will have capabilities beyond isolation detection and will become active power controllers that can provide reliability services. These reliability services may include voltage support, voltage regulation, and frequency regulation.

In addition, the California Public Utilities Commission (CPUC) regulates the largest rollout of DER in North America in the California ISO balancing area and sets the technical and commercial standards for DER interconnection and operation according to CPUC Rule 21. The CPUC has implemented new technical standards for the DER systems that are intended to go beyond safety and hazard issues and "establish programmable functions" that DER systems will perform to support power system operations. However, the majority of existing fleet of DER conforms to IEEE 1547-2003. Therefore, the performance of the existing DER fleet is unlikely to change until normal equipment replacements occur. Nevertheless, the performance of the installed fleet could change rapidly with the rapid growth of new PV that complies with new interconnection standards.

Voltage Ride-Through (VRT) and Frequency Ride-Through (FRT) Characteristics and Consequences

The voltage and frequency performance of DER is currently not coordinated with BPS requirements. DER resources are not explicitly modeled as generating resources in operating and planning analysis tools either in real-time or off-line studies. Therefore, an event that causes a large amount of DER to isolate from the power grid could result in unpredicted BPS behavior. The most likely event is low voltages over a wide geographic and electrical area caused by a fault on the sub-transmission (<230kV) systems connected to load and DER. Fault clearing times are often dictated by relay coordination issues, which can lead to longer fault clearing times, particularly at lower voltages.

However, faults on the sub-transmission system can result in low voltage at the DER resulting in the isolation of that resource. Consequences of this isolation could be more severe fault induced voltage recovery (FIDVR) or a significant increase in perceptible BPS load until the DER resources reconnect to the power grid. To date, in most areas, these problems have not become very noticeable. However, system performance at 5 percent DER penetration will differ from that where DER are at 25 percent penetration. Loss of a large amount of DER during a fault could result in system performance similar to the loss of a BPS generator. If the potential separation of DER approaches a Balancing Authority's Most Severe Single Contingency (MSSC), care must be taken to ensure that adequate contingency reserves are available for such an event.

Similar issues apply for frequency ride-through. In WECC, the largest credible generation contingency is the outage of two nuclear units at the Palo Verde plant. This could result in a loss of 2,740 MW with a resulting frequency decline of 0.29 Hz, or a 59.71 Hz nadir (BAL-003-1 interconnection frequency response obligation (IFRO) calculation for WECC). This is above the IEEE 1547 separation point of 59.3 Hz. However, the WECC Off-Nominal Frequency Plan begins tripping at 59.5 Hz and continues tripping down to 58.3 Hz. If UFLS event occurred, DER are likely to trip off-line at 59.3 Hz, dramatically increasing perceptible load on the BPS and further depressing frequency. It is important to recall that IEEE 1547 specifies minimum performance requirements: DER equipment manufactures may exceed 1547 trip requirements resulting in DER tripping before 59.3 Hz is reached. This implies that significant DER separation could occur at frequencies higher than 59.3 Hz, but all separation would occur by 59.3 Hz.

With respect to the BPS, voltage and frequency ride-through are key to system performance. Today, DER resources are typically netted with distribution load when measured and modeled. Consequently, the operator of the power grid is not aware of the total load and total interconnected DER. If a system event occurs, be it a voltage or frequency excursion, and that excursion exceeds the inverter isolation settings, it is likely that a significant amount of DER may automatically disconnect. This can instantaneously and significantly increase net load during such an event, thereby exacerbating the underlying disturbance that caused the voltage or frequency excursion. The impact of the change in net load is proportional to the amount of DER that isolates from the power grid. As DER penetration increases, the effects of this sudden load surge on the BPS increase.

The existing IEEE 1547-2003 performance requirements for voltage and frequency ride-through are documented below. These requirements have been overlaid with NERC's frequency and voltage requirements (PRC-024 Attachment 1 and 2, respectively) and illustrate areas of concern where large penetrations of DER could adversely impact reliability. DER must isolate when these conditions are met as shown in Table 4.1 and Figure 4.1 for voltage ride-through and in Table 4.2 and Figure 4.2 for frequency.

Table 4.1: Voltage Ride-Through Conditions (DER must isolate when these conditions are met)

DER Size	Voltage (pu)	Isolation Times (seconds)
≤ 30 kW	< 0.50	0.16
	0.50 < 0.88	2.0
	0.88 < 1.10	Run Continuously
	1.10 < 1.20	1.0
	≥ 1.20	0.16
> 30 kW	Tripping points are field adjustable	

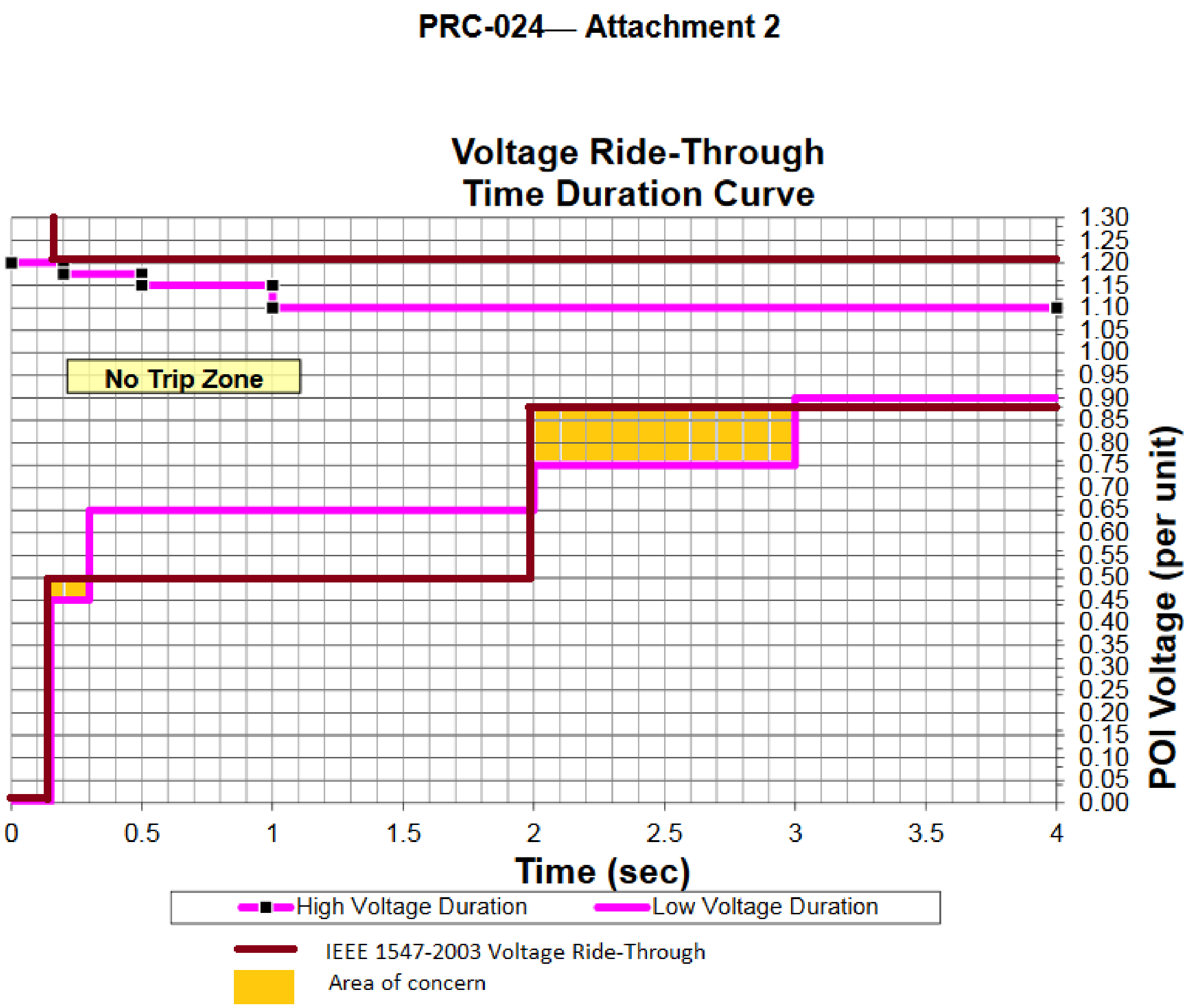


Figure 4.1: NERC PRC-024-2 and IEEE 1547-2003 Voltage Ride-Through

Table 4.2: Frequency Ride-Through Conditions (DER must isolate when these conditions are met)		
DER Size	**Frequency Range (Hz)**	**Clearing Times (sec)**
≤ 30 kW	> 60.5	0.16
	< 59.3	0.16
	> 60.5	0.16
> 30 kW	< 59.8 – 57.0 adjustable	0.16 – 300 adjustable
	< 57.0	0.16

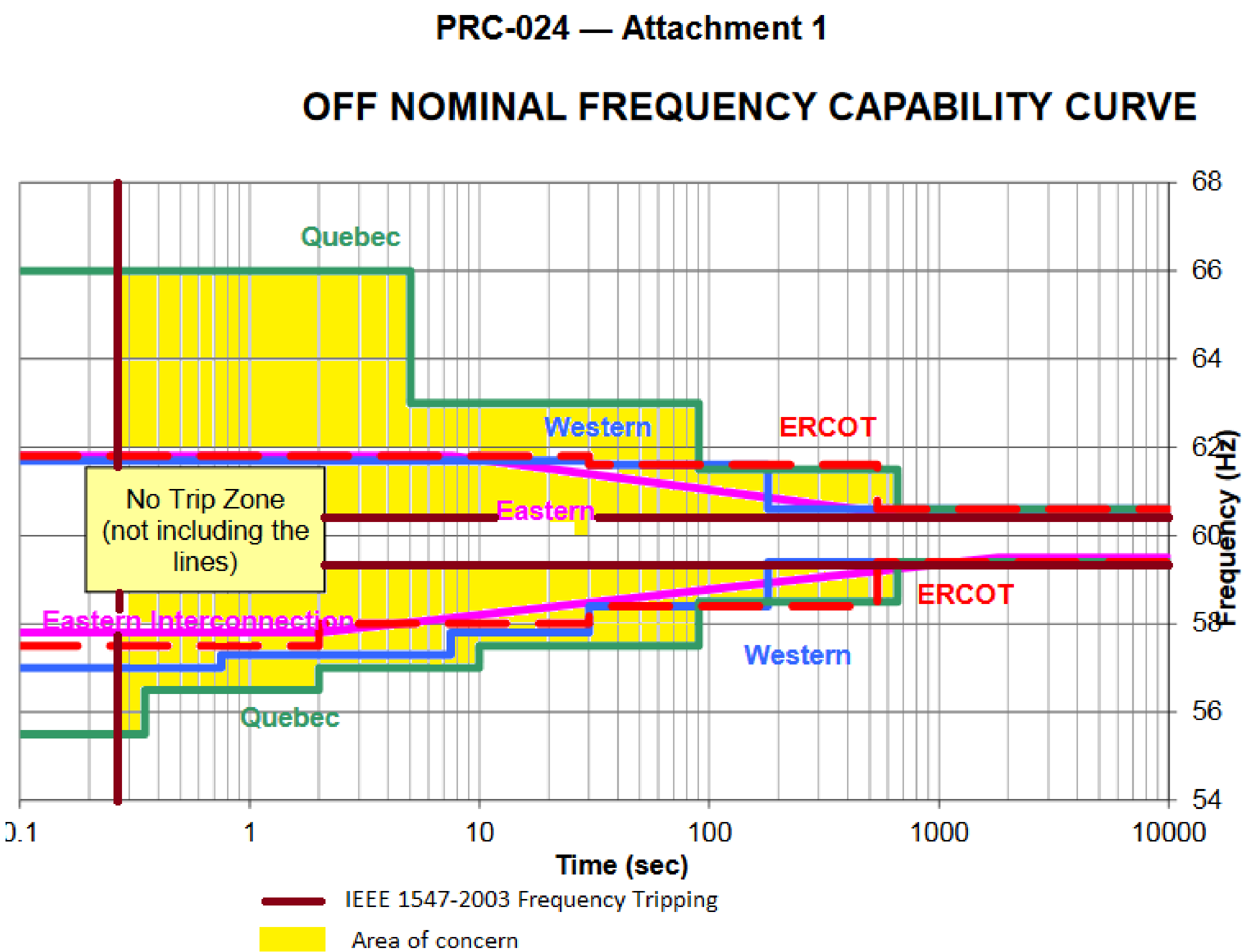


Figure 4.2: NERC PRC-024-1 and IEEE 1547-2003 and Frequency Ride-Through

PRC-024-2 frequency ride-through requirements are designed such that UFLS schemes will operate before generators begin to disconnect from the BPS. Smaller DER installations, under 30 kW, can begin disconnecting from the BPS without respect to coordination with the area UFLS. When DER disconnect, BPS net load will increase. This will further depress frequency, potentially leading to premature system instability.

IEEE 1547-2003 currently prohibits energizing the DER if the area is de-energized/islanded, which precludes independent operation of DER. This is done largely for safety considerations so that islanding does not result in energized lines. In broad terms, DER can be considered “passive” resources in the sense that they do not directly regulate voltage or frequency. From the point of energy balance, DER operate as a “negative load.”
IEEE 1547 is currently being updated to include frequency and voltage ride-through capability that can better support BPS reliability. Other topics of discussion for updates within the IEEE 1547 standard include voltage and frequency regulation capabilities and communications. These efforts are ongoing, but will not affect DER that is installed before the revisions become effective. The DERTF supports the concepts being proposed to IEEE 1547 that allow for situational awareness.

California Rules for DER

The California Public Utilities Commission (CPUC) regulates the largest rollout of DER in North America in the California ISO balancing area. It also sets the technical and commercial standards for DER interconnection and operation according to its Rule 21. Rule 21 primarily follows the IEEE 1547 parallel operation DER interconnection standard where generation is operating in parallel (synchronously connected) with the system rather than in an islanded or isolated mode. CPUC is in the process of implementing new technical standards for the DER systems that are intended to go beyond safely and hazard issues and "establish programmable functions" that DER systems will perform to support power system operations. A report prepared by the CPUC Smart Inverter Working Group notes: [6]

> "[An] increasing number of DER systems can impact the stability, reliability, and efficiency of power grid operations. First, DER systems are usually located for the convenience of the DER owner, not the utility, and therefore may be in less-than-optimal locations from the perspective of grid operators. Second, DER systems are of widely varying sizes and purposes (e.g., as secondary to offsetting customers' loads and/or their power production). Third, without coordination with the distribution equipment on the grid, DER systems could actually cause voltage oscillations, create reverse power flows on circuits not designed for two-way flows, and cause other power system impacts that could actually increase the frequency and durations of outages."

The CPUC report not only covers the new standards for DER systems but also notes how utilities will be able to monitor and control these systems and their functions. Most notably:

> "DER systems can respond to commands to override or modify their autonomous actions by utilities and/or retail energy providers. In some cases, DER systems, just like bulk power generation, may be directly monitored and controlled by utilities in real-time. In other cases, these ICT [Information and Communications Technology] capabilities may issue emergency commands, or may support normally autonomous operations by updating software settings, providing demand response pricing signals, establishing schedules for energy and ancillary services, adjusting the curves for active and reactive power, and other types of utility-DER interactions."

Per CPUC plans, the following autonomous inverter functionalities will be added to the technical operating standards in Rule 21 by the end of 2017:

1. Support anti-islanding to trip off under extended anomalous conditions;
2. Provide ride-through of low/high voltage excursions beyond normal limits;
3. Provide ride-through of low/high frequency excursions beyond normal limits;
4. Provide volt/VAR control through dynamic reactive power injection through autonomous responses to local voltage measurements;
5. Define default and emergency ramp rates as well as high and low limits;
6. Provide reactive power by a fixed power factor; and
7. Reconnect by "soft-start" methods.

The implementation road map, as recommended by the CPUC Smart Inverter Working Group, consists of the following:

[6] CPUC Smart Inverter Working Group, "Recommendations for Updating the Technical Requirements for Inverters in Distributed Energy Resources," January 2014.

1. A nationally recognized testing laboratory or laboratories have made an accepted revised ANSI/UL 1741 testing procedure available to test the added autonomous inverter functionalities noted above;
2. Immediate modification of Rule 21 to allow the installation of certified inverters that include the proposed autonomous inverter functionalities applying for interconnection under Rule 21;
3. Consideration of an 18-month transitional permissive period during which the investor-owned utility distribution provider and the DER system installer may, by mutual agreement during the interconnection process, activate one or more of the autonomous functionalities for the purposes of conducting pilot operations, analysis, and publishing the results of any analysis;
4. Following the transitional permissive period and based on operational data collected and published during that period as well as any other relevant factors, CPUC would mandate the autonomous smart inverter functionalities for inverter-based distributed energy systems applying for interconnection under Rule 21; and
5. Upon further recommendations and future proposals by the CPUC Smart Inverter Working Group, CPUC would consider communications capabilities and advanced inverter functionalities for inverter-based distributed energy systems in California.

In addition to the autonomous inverter functionalities noted above, CPUC is evaluating the implementation of the following advanced communication functionalities for inverter based DER systems:

- Provide capability for including and/or adding communications modules for different media interfaces;
- Provide the TCP/IP internet protocols;
- Use the international standard IEC 61850 as the information model for defining data exchanges;
- Support the mapping of the IEC 61850 information model to one or more communications protocols;
- Provide cybersecurity at the transport and application layers; and
- Provide cybersecurity for user and device authentication.

Finally and beyond the autonomous inverter and communication functionalities noted above, CPUC will consider the following advanced functionalities for the DER systems in the future:

- Provide emergency alarms and information;
- Provide status and measurements on current energy and ancillary services;
- Limit maximum real power output at the Point of Common Coupling (PCC) upon a direct command from the utility;
- Support direct command to disconnect or reconnect;
- Provide operational characteristics at initial interconnection and upon changes;
- Test DER systems software patching and updates;
- Counteract frequency excursions beyond normal limits by decreasing or increasing real power;
- Counteract voltage excursions beyond normal limits by providing dynamic current support;
- Limit maximum real power output at the Electrical Connection Point (ECP) or optionally at the PCC to a preset value;
- Modify real power output autonomously in response to local voltage variations;
- Set actual real power output at the point of common coupling (PCC);

- Schedule actual or maximum real power output at specific times;
- Smooth minor frequency deviations by rapidly modifying real power output to these deviations;
- Follow schedules for energy and ancillary service outputs; and
- Set or schedule the storage of energy for later delivery, indicating time to start charging, charging rate and/or “charge-by” time.

Chapter 5: Previous Work of the NERC IVGTF Task Force

NERC has taken a detailed look at the potential impacts of DER on the BPS in the form of solar photovoltaic systems (PVs) on the distribution system. This work was documented in the NERC Integrating Variable Generation Task Force Task 1-7 report entitled *Performance of Distributed Energy Resources During and After System Disturbance: Voltage and Frequency Ride-Through Requirements*[7] that was issued in December 2013.

This earlier NERC task force stated that a large amount of distribution-connected generation may have significant effect on the reliability of the BPS. Of particular concern was the lack of disturbance tolerance, which entails voltage ride through (VRT) and frequency ride through (FRT) capability. Other than CPUC Rule 21, which was recently implemented, there are currently no North American VRT or FRT DER requirements in place today.

The Integration of Variable Generation Task Force (IVGTF) made the following general recommendations in its report:

- In the short-term, NERC should engage in current efforts to revise DER interconnection standards by providing information, raising awareness and encouraging the adoption of VRT and FRT for DER. The initial focus should be on identifying the need for adopting minimum tolerance thresholds for VRT and FRT in the IEEE Standard 1547 and, then, establish those minimums.
- In the longer-term, NERC should establish a coordination mechanism with IEEE Standard 1547 to ensure that BPS reliability needs are factored into future DER interconnection standards revision efforts. To date, BPS stakeholders have participated only sporadically in the IEEE Standard 1547 process. As a result, VRT and FRT concepts receive limited consideration and may have been outweighed by distribution system protection concerns. This liaison process would be too late for the P1547a amendment, but it would be timely for the full revision to begin in December 2013.

The IVGTF offered the following general guidelines on voltage ride-through (VRT) and frequency ride-through (FRT) specifications for distributed VER and other DER, for consideration in the IEEE Standard 1547 revision [43]. It is assumed that VRT and FRT requirements would have to co-exist with revised "must trip" provisions needed to address safety and protection/coordination issues in distribution systems.

1. The revised IEEE Standard 1547 should allow for different methods of meeting the functional requirements of fault detection (clause 4.2.1), reclosing coordination (clause 4.2.2), and unintended islanding detection (clause 4.4.1). At present, DER meeting those functional requirements would still have to trip on voltage (clause 4.2.3) and frequency (clause 4.2.4) excursions. Removing those linkages would help pave the way for VRT and FRT requirements. The IVGTF recognized that these alternative methods are more expensive, require more engineering effort, and in some cases require further technical development. However, the increasing level of DER and the potential impact on the BPS justifies the effort.
2. The revised IEEE Standard 1547 should include explicit low and high VRT requirements. Likewise, the revised IEEE Standard 1547 should include explicit low and high FRT requirements. These requirements should be expressed as voltage versus cumulative time and frequency versus cumulative time.
3. Must-trip voltage thresholds in the existing IEEE Standard 1547 should be extended to accommodate an effective VRT envelope without overlap (Figure 5.1).
    a. As an example, Figure 5.1 shows a possible approach for low voltage ride-through down to 50 percent voltage for 10 cycles (160 milliseconds), within the existing IEEE Standard 1547 framework.
    b. Zero voltage ride-through is not required for BPS reliability. A ride-through level down to approximately 50 percent voltage would provide adequate tolerance during transmission faults.

[7] Performance of Distributed Energy Resources During and After System Disturbance: Voltage and Frequency Ride-Through Requirements

c. A ride through period longer than shown in Figure 5.1—possibly greater than 10 seconds—at higher voltage level (e.g., down to 70 percent voltage) may be needed to avoid compounding fault-induced delayed voltage recovery (FIDVR).

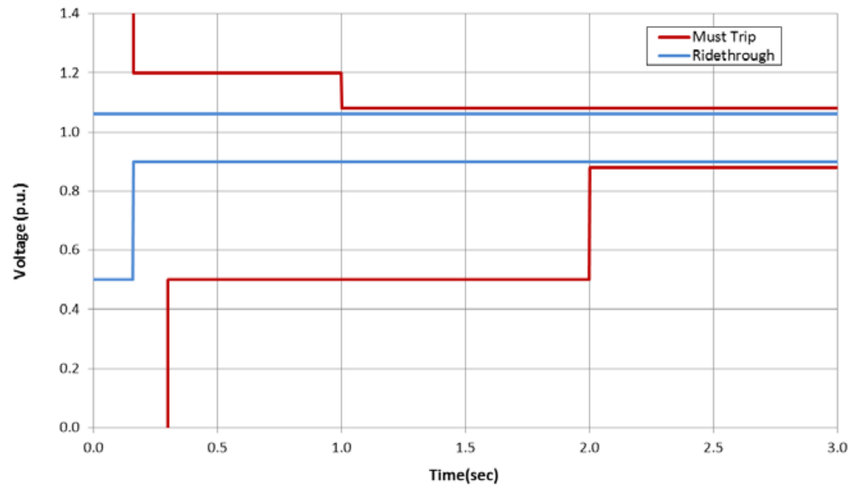


Figure 5.1: IVGTF 1-7 Recommended Ride-Through and Must-Trip Requirements for DER

4. Must-trip frequency thresholds in the existing IEEE Standard 1547 should be extended to accommodate an effective FRT envelope without overlap.

5. The time dimension of the VRT/FRT curves discussed previously represents cumulative time elapsed since the onset of a disturbance event that result in temporary excursions of voltage and/or frequency. The VRT/FRT envelopes should not establish must-run ranges for generators (i.e., they should not prevent intentional shutdown of a DER for reasons other than grid voltage and frequency disturbances, such as normal shutdown of PV at night or by operator action.)

6. The prospective disturbance tolerance standard should provide a default VRT and FRT envelope, but should allow for the time and frequency/voltage magnitudes to be adjustable, within certain limits, for coordination with local protection, in coordination with the distribution system operator.

7. FRT and VRT requirements should cover all DER that are normally grid connected, regardless of size or technology. However, a range of thresholds could be considered based on technology differences (e.g., inverter versus rotating machines), as some European grid codes do. In general, focusing requirements on the truly functional needs of the grid tends to eliminate the need to have technology-specific requirements.

8. The restarting of DER during system restoration should be considered during the development of DER interconnection requirements. While the restoration situation in North America is somewhat mitigated at present by the sequential nature in which distribution feeders will likely be re-energized after a major blackout, reliability impacts of DER should consider the automatic restarting of DER. Failure to consider and mitigate these impacts could lead to further instability during a disturbance.

Since this IVGTF report was posted in December 2014, efforts have commenced to harmonize the PRC-024-2 VRT and FRT requirements with IEEE 1547. Several ERSWG and DERTF members have been participating in IEEE 1547 Subgroup III Section 4.2 (voltage and frequency ride-through). As of this writing, it appears that the 1547 update will respect PRC-024-2 voltage and frequency ride-through requirements. As always, it will be incumbent on the local distribution owner/operator to ensure that IEEE 1547 are understood and implemented properly.

Chapter 6: NERC Reliability Standards

Background

NERC Reliability Standards exist to address the reliability needs of the interconnected electricity systems. These standards apply to the bulk electrical system (BES) as specified by the BES definition adopted by FERC in March 2014. In some cases, standards apply to devices and needs beyond the BES. Historically, standards have not been written to apply to equipment within the distribution utility unless it has a direct impact on the effect of grid reliability, such as load shedding or system restoration. Each standard identifies the applicable registered entities, and distribution providers are identified as applicable entities for some of the standards.

NERC generation standards, generally, do not address resources connected to the grid at voltages below 100kV, nor do they address resources with less than a registered capacity of 75MVA in aggregate or 20MVA for an individual unit. The standards do not explicitly address energy resources (e.g., solar, wind, or hydro facilities) that are contained within the distribution system footprint. However, some standards provide for the collection of pertinent information for planning and system operations purposes.

The impact of DER on the BPS is not a simple issue. Over the last several decades, the electric industry has operated with the majority of its generation integrated at the transmission system level. More recently, there has been a greater integration of generation resources within the distribution system under the support of renewable portfolios and societal expectations for a modernization of the grid. These changes have altered the power flows at the transmission-distribution (T-D) interface. Whereas distribution entities have drawn their generation needs from the BPS in the past, some distribution entities are increasingly a source of resources that will support some local needs or even flow power back to the BPS. At lower penetration levels, the overall impact of DER is minor and insignificant to the BPS; as the output of these resources varies throughout the day or if these resources were to trip off-line during large system disturbances, the changes imposed to BPS voltage and frequency are minor and are managed by existing BPS resources. However, as the penetration of DER increases, their impact on the BPS becomes more substantial. At higher penetration levels, issues may develop in transmission line loading, grid voltage, and system frequency during normal or disturbed operation. These actions will have similar impacts to those that NERC described in the ERS report published in December 2015.

Accurate models for the operation and planning processes are vital, and it is necessary for system planners and operators to have access to information regarding the capacity and behavior of DER at the T-D interface. Refined information and models allow planners and operators to make more informed decisions regarding resource adequacy, system improvements, recovery and demand balancing for the BPS. The addition of DER may initially appear to simply reduce the demand and the loading levels at the T-D interface, but the reality is actually more complex. Both planning and operating assessments need to accurately represent how DER interacts with the complex load characteristics of the distribution system. The inclusion of DER in models and assessments yields valuable insight into how the BPS will perform and how distribution level resources can impact operating limits and margins in the interconnected system.

Review of Existing NERC Standards

The DER task force reviewed the current set of NERC standards and determined there is no need for additional standards to be developed to address an increasing penetration of DER. However, the DERTF recommends that DP be added as an applicable entity in MOD-032, replacing the Load Serving Entity, which is a current applicable functional entity. MOD-032 provides planning coordinators and transmission planners with the mechanism to collect data necessary for steady state, dynamics, and short circuit modeling from applicable entities.

While there are no explicit NERC requirements to independently model and assess DER for purposes of BES system planning or operations, the transmission operators and transmission planners have requirements to accurately model and address reliability risks. This includes the impact of DER, where material. Current standards (TOP-003-3, IRO-010-2, & MOD-032-1) provide broad authority for system operators and transmission planners to obtain the information needed for models and reliability assessments. This provides the ability to collect pertinent information as related to distribution impacts on the BES. As described in Chapter 3, the necessary DER information can generally be in somewhat aggregated form, but with enough detail to allow accurate modeling of the characteristics and behaviors at the transmission-distribution (T-D) interface. This level of detail also extends to forecasting and operating issues. With this in mind, additional analysis is needed to ascertain how an increasing penetration of resources within the distribution system footprint will influence the change of power flows at the T-D interface. The DERTF recommends that a set of guidelines be developed to assist in modeling and assessments, such that owners/operators of the BPS can account for the impact of DER at the T-D interface.

Chapter 7: Recommendations

The recommendations of the DERTF are listed below. The DERTF has completed the scope for the task force, and additional efforts should be part of ongoing ERSWG efforts.

- **Guidelines:** The DERTF recommends that a set of guidelines be developed to assist in modeling and assessments, such that owners/operators of the BPS can account for the impact of DER. The DERTF also recommends that Distribution Provider (DP) be added as an applicable entity in MOD-032, replacing the Load Serving Entity that is currently an applicable entity, to provide for collecting pertinent information related to distribution impacts on the BPS (similar to what is already included in TOP-003-3).
- **Data Sharing:** Data requirements and sharing of information across the transmission-distribution (T-D) interface should be further evaluated to allow for adequate assessment of future DER deployments. The important near-term issue is sharing of information to facilitate accurate modeling for transmission planning and operations. At some point, additional consideration may be needed for stability, protection, forecasting, reactive needs, and real time estimates for operating needs.
- **Modeling:** Based on reliability considerations for modeling purposes, generation from DER should not be netted with load as penetration increases. Load and DER should be explicitly modeled in 1) steady-state power flow and short-circuit studies, and 2) dynamic disturbance ride-through studies and transient stability studies for BPS planning with a level of detail that is appropriate to represent the aggregate impact of DER on the modeling results over a 5 to 10 year planning horizon. A modular approach to represent DER in BPS studies, with some level of data validation, is recommended to ensure accurate representation of the resources for the specific BPS study type.
- **Dynamic Models:** Dynamic models for different DER technologies are available and should presently be used to model the evolving interconnection requirements and related performance requirements. WECC's simplified distributed PV model (*PVD1*) provides a reasonable balance between modeling accuracy, computational requirements, and handling of the system model, but some further improvement may be needed.
- **Coordination:** A coordinated effort by distribution and transmission entities is needed to determine appropriate use of future DER capabilities (such as settings available under proposed IEEE 1547 revisions [43]). This must be coordinated with voltage and frequency ride through performance and potentially coordinated with UFLS programs and BPS performance under PRC-024. Note that PRC-024 was developed with BES issues in mind, and where PRC-024-2 and desired distribution-level protection and operations conflict, the transmission and distribution utilities will need to coordinate the required DER ride-through settings to meet BPS reliability needs while minimizing distribution impact.
- **Definitions:** Further examination is needed to determine whether DSM should be included in the DER definition and if the DER definition should be added to the NERC glossary and/or NERC functional model.
- **Industry Collaboration:** Finally, the limited existing knowledge and experience of modeling DER in system planning studies and operating with higher levels of DER will require future collaborative research, knowledge exchange, and learning. The industry should collaborate with vendors of power system simulation software and DER product vendors to continuously enhance models for DER representation in BPS planning studies. NERC can assist with coordination across the industry to facilitate the reliable integration of DER into the BPS.

Appendix A: Typical Connection of DER

While defining DER is an important first step, to fully understand the potential interaction of these resources with the BPS, it is essential to understand how these resources are interconnected to the power grid.

DER, as defined within this document, are generally interconnected to a Distribution Provider's electric system at the primary voltage (≤ 100 kV but > 1 kV) and/or secondary voltage (≤ 1 kV). Interconnection design and installation typically meet requirements of the National Electric Code, the National Electrical Safety Code, or any other locally designated code pertaining to electrical facility design, construction, or safety. Sample interconnection one-line diagrams of different types of DER that are currently operating in parallel with a distribution provider's electric system are shown in the following figures. Shown in each figure are a point of change of equipment ownership, bi-directional meter, and a visible air-gap switch.

The point of change of equipment ownership (POCEO) defines the point where equipment owned and operated by the DER owner connects to equipment owned and operated by the distribution provider. Design and installation of equipment on either side of the POCEO is the responsibility of the owner of the equipment.

The bi-directional meter has two registers. One register captures energy flow from the distribution provider's electric system to the DER facility (i.e., delivered energy). The other register measures energy flow from the DER facility to the utility (received energy). Depending on the power purchase agreement (PPA) executed between the DER owner and the distribution provider determines the type of meter installed. In some cases, the distribution provider may install an advanced meter with capability of capturing 30-minute interval real power (kW), reactive power (kVA), and real energy (kWh). In other cases, a simple energy meter is installed.

A visible air-gap switch is sometimes required for isolating the DER facility from the distribution provider's electric system when work on a line section or equipment is performed, particularly for large DER. The switch is generally required for the purpose of providing a visibly verifiable break (or air gap) between the facility and the distribution provider's electric system. Smaller DER systems may or may not be required to have a visible air-gap switch. All DER fed from DC sources are required to have a lockable DC disconnect switch.

The bidirectional-meter and visible air gap switch are minimum interconnection requirements for some distribution providers. Other requirements include intertie protection that is designed to quickly isolate the DER facility faults within the distribution provider electric system. The intertie protection may include a communication link between the DER facility and the distribution provider's electric system to prevent unintentional islanding.

A separate intertie protection is generally not required for inverter-based DER facilities that are Underwriters Laboratory (UL) listed, meets the utility compatibility requirements of UL Standard 1741 and the protection requirements of Institute of Electrical and Electronic Engineers (IEEE) Standard 1547-2003, and are determined to be capable of detecting faults on the utility side of the DER facility. However, the distribution provider generally performs commissioning testing of the DER facility to ensure that the IEEE 1547 protection is properly set and configured for parallel operation with the distribution provider's electric system. IEEE 1547 is currently under revision [43] and is discussed in Chapter 3.

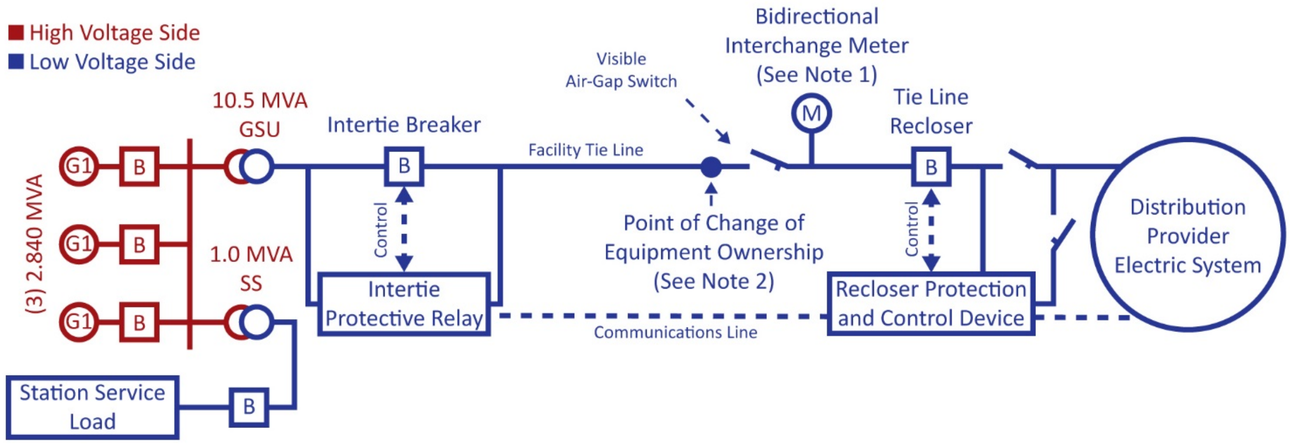


Figure A.1: Interconnection of a Large Landfill Gas Generation Facility

System impact studies performed by the distribution provider identified the need for a communications line for direct transfer trip of the DER facility. A tie-line recloser is required to maintain reliability of service to existing end-use customers served by the distribution provider.

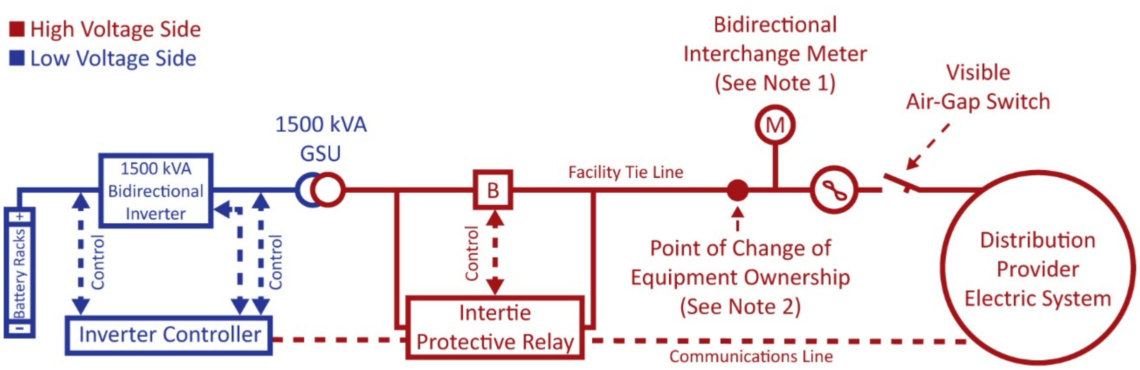


Figure A.2: Interconnection of a Large Battery Energy Storage Facility

The inverter is not UL listed. Therefore, a separate intertie breaker with relays is required. System impact studies performed by the distribution provider identified the need for a communications line for direct transfer trip of the DER facility.

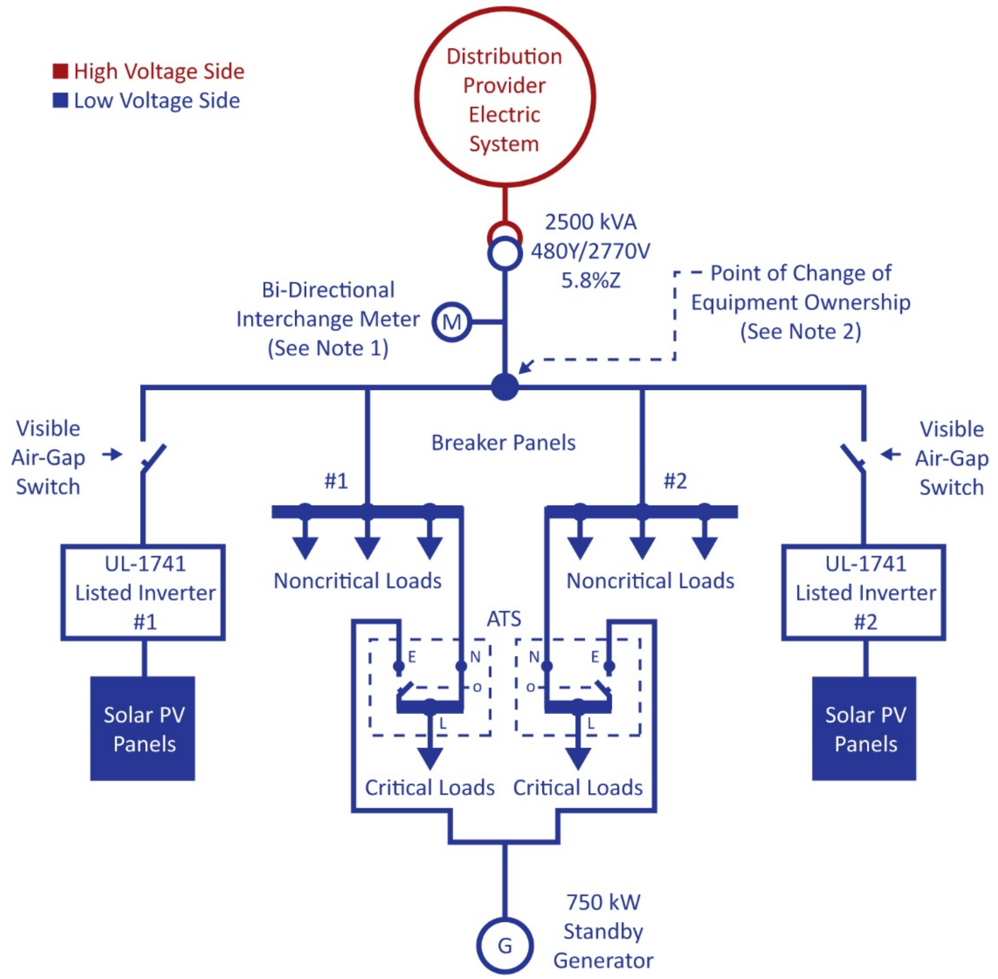


Figure A.3: Interconnection of a Behind-The-Meter Solar PV Facility at a Large Commercial Customer Site with an Existing Standby Generator

Two UL-1741 listed inverter-based solar PV systems were installed primarily to offset electricity purchased from the distribution utility. In addition to this DER, customer also has a standby generator that can be used to serve critical loads within the facility.

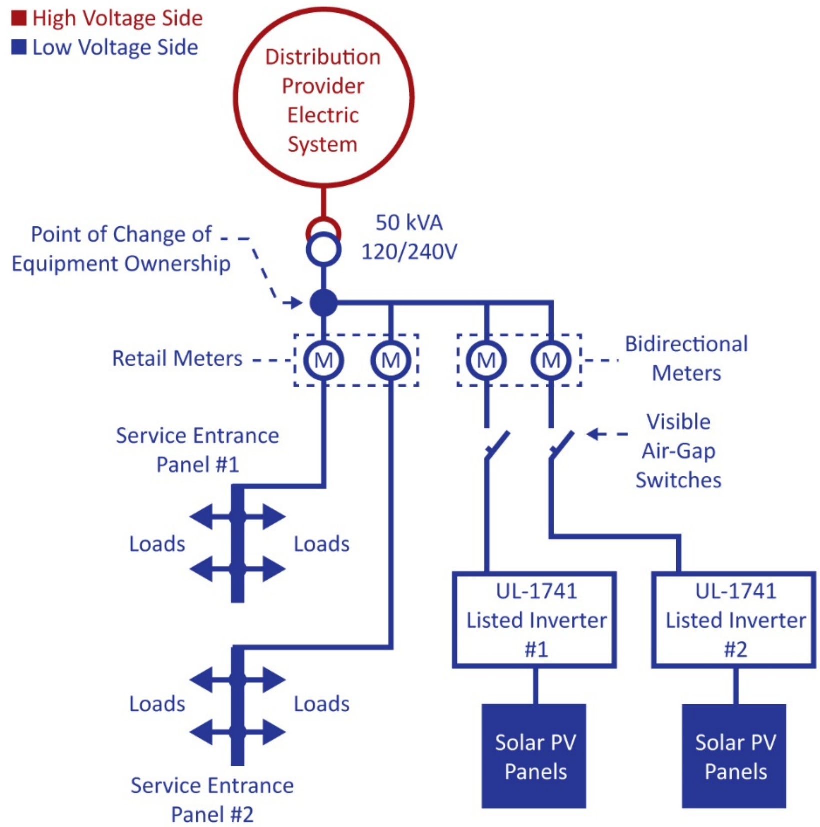


Figure A.4: Interconnection of a Solar PV Merchant Facility at a Residential Customer Site

DER facility output is sold to the distribution provider through the bi-directional meter. The distribution provider provides electric service to the customer's residence through two retail revenue meters and two service entrance breaker panel boards.

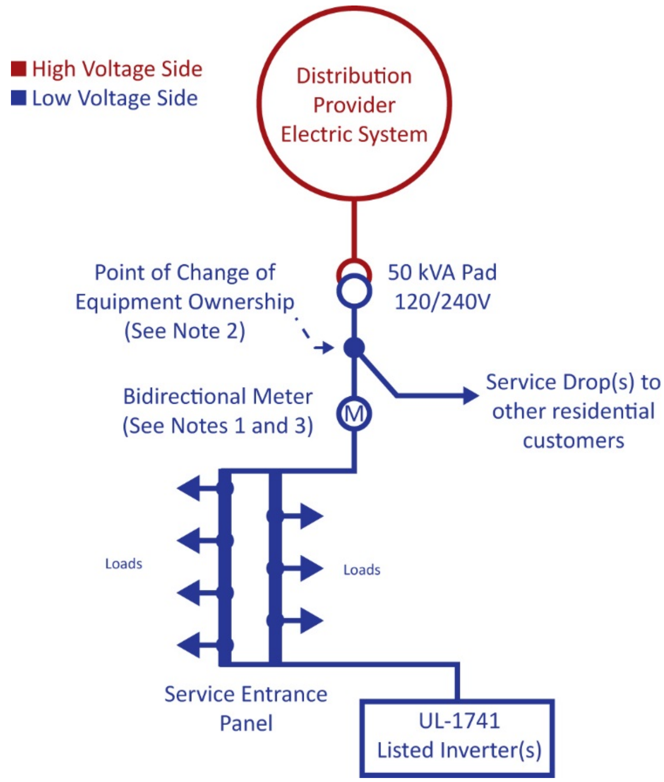


Figure A.5: Interconnection of a Behind the Meter Solar PV Merchant Facility at a Residential Customer Site

A single UL-1741 listed inverter-based system was installed to affect electricity purchased from the distribution utility. Net output from the facility is sold to the distribution provider through a bidirectional meter.

Appendix B: Operations and Long-Term Planning

As discussed throughout this report, the growth in quantity and diversity of DER require enhanced short-term forecasting for operational purposes, operational coordination between the BPS operator and the distribution utilities, and long-term forecasting for planning. It is also important to have situational awareness of DER contributions and impacts in the operating timeframe, as well as to understand the ability of DER to participate as a dispatchable resource and that they contribute ERS to the power grid in various ways.

This appendix provides an example of how these requirements are being viewed and addressed in California along with some general discussion. Given the many options and developing approaches to these topics, the DERTF offers some initial information in this appendix, but recommends that these topics receive additional consideration in future NERC task force, working group, or subcommittee activities.

DER Impact on California ISO Operations

Currently the greatest operational impact of DER in California comes from behind-the-meter solar photovoltaic (PV) installations. Figure B.1 is the latest forecast of PV growth in the CAISO Balancing Authority area (BAA).

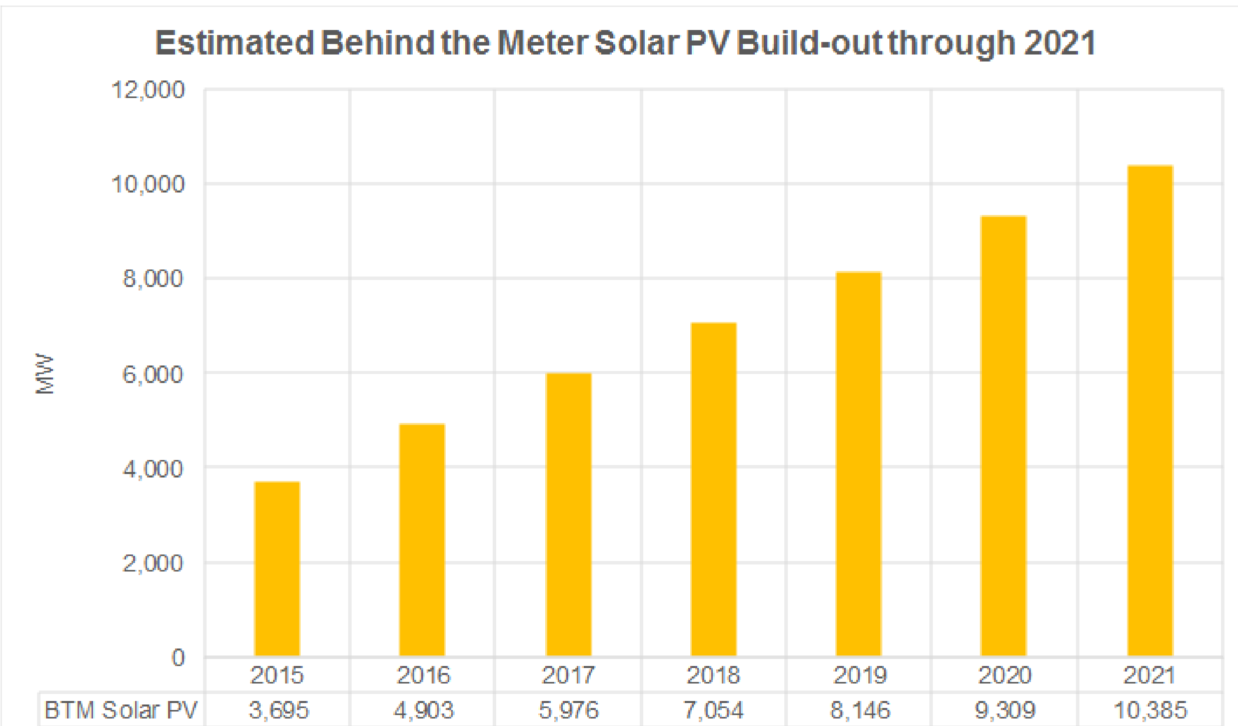


Figure B.1: CAISO Behind the Meter (BTM) PV DER forecast

CAISO's forecasted peak load in 2015 was 44,500 MW. In 2016, DER PV was over 10% of CAISO's peak load. At lower loads, DER PV is a higher proportion of load. Voltage and frequency ride-through will not conform to BES requirements of PRC-024-2. BA load (such as for CAISO) is a calculated value consisting of net interchange and metered generation values.

BA Load = Generation + Net Actual Interchange

Behind-the-meter DER are not typically metered. In general, its effect is to reduce the amount of generation or net imports needed for system balance (i.e., the right-hand side of the above equation). Thus, DER directly lowers the measured load in a BA. In Figure B.1, the "BTM Solar PV" value represents an equivalent amount of load that is not measured at the BA level.

In operations (resource commitment and dispatch) and planning (future needs) work, DER represent another variable to consider; a distribution circuit with a 10 MW load may see increasing DER penetration over time. Assuming the actual physical load remains 10 MW, DER will offset that value. Assuming a 50% penetration of PV, the distribution circuit load may see 5 MW of load at the circuit breaker, but the 10 MW of load is still there. As the solar angle decreases through the afternoon and evening, DER output will steadily decline while load remains high. This leads to lower than expected loads during the day with circuit load increasing much faster through the late afternoon and evening hours. Ultimately, the circuit peak load can be 10 MW, but it occurs in the evening rather than in late afternoon. Circuit load during the morning and early afternoon will be lower than previously experienced. Therefore, there is low resource commitment during the early part of the day, but very fast resource commitment and ramping requirements in late afternoon and evening. This is followed by a very fast de-commitment from evening to light load night hours. Each of these situations can challenge the operational capability of the system. Figure B.2 shows that actual net load is lower than originally estimated due to increased amount of renewable resources (including DER) on the CAISO system.

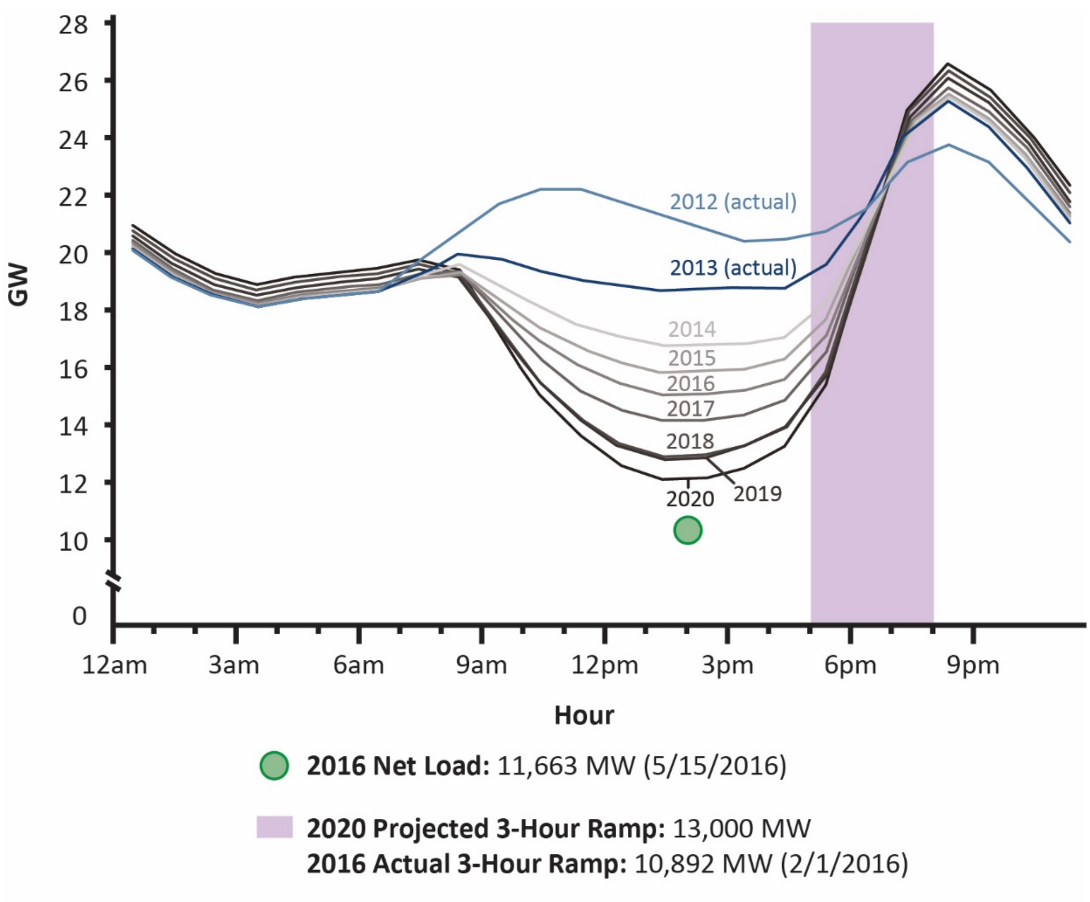


Figure B.2: CAISO Load Profile

DER Forecasting for Operations and Planning

Long-term DER forecasting for planning purposes must address 1) the DER adoption or growth scenarios, and 2) the impact on net load of DER performance or autonomous behavior. Much of DER adoption and behavior may be characterized as autonomous, that is, driven by the needs of energy end users of all types whose interest is not in kWh per se but in the services they require at their residences and businesses. A challenge for planning is to forecast the adoption of various DER types over a planning horizon of ten years or more with sufficient locational granularity for identifying and planning needed BPS infrastructure upgrades. In addition to adoption, planners need to know how the performance or behavior of the DER will affect the net load at each T-D interface in terms of total energy, peak demand, and load profile.

When DER are comprised mainly of solar PV, forecasting behavior is manageable with good estimates of installed capacity by T-D interface and high-quality weather data. The composition of DER will soon become more complex, with more widespread installation of storage devices, PV combined with battery storage and penetration of electric vehicles. Current proceedings underway at the California Public Utilities Commission include developing methods and provisions for DER to substitute for distribution infrastructure investment and offer real-time operational services to the distribution utility. In many cases the CPUC provisions will entail “multiple-use” applications where specific DER may be located behind the retail meter to provide load management services to the customer. DER may also provide services to the distribution utility, and may be aggregated across multiple sites to form a virtual resource that participates in the wholesale market.

Short-term and long-term forecasting of DER behavior is difficult due to current modeling practices. In order for the CAISO to issue accurate dispatch instructions to balance supply and demand on the BPS, it needs accurate forecasts of net load at each T-D substation, looking ahead from 5 minutes to two or three hours. In this case, however, the installed capacity by resource type and T-D interface location should be well known to whichever entity is responsible for the forecast (distribution utility and/or BPS operator), as would any agreements between DER providers and distribution utilities for investment deferral or real-time services. Thus, uncertainty about the adoption of DER should not be part of the short-term forecasting problem.

Discussion

Reliable BPS operations requires grid operators to monitor the supply and demand balance and the state and availability of BPS elements, and the ability to accurately forecast the near term changes in load, availability of supply resources, state of transmission facilities, and external factors such as weather. This monitoring and forecasting is considered “situational awareness” and is required to dispatch the system and direct actions in response to unexpected disruptions. System dispatch relies on a sufficient quantity of generating resources under direct control to be able to provide voltage control, frequency support, and ramping capability such as essential reliability services (ERS) to balance and maintain the electric grid.

Traditionally, the basic grid operation is a free flowing transmission network connecting central station generation resources to load/demand buses with flow in a one-way direction to satisfy the load. The introduction of DER challenges the basic model of BPS operations as the load/demand bus now may become a source, or at the very least, cause a reduction in demand at a load bus. In addition, as stated in previous sections, the nature and characteristics of the load/demand bus in models is changing and impacting the expected needs and response of the system.

As the introduction of DER into the electric system are explored, several challenges become apparent:

- Transparency and observability of DER supply on the BPS
- Nature of the DER capabilities, typically inverter bases, ability to supply the ERS
- Variability of the DER supply by fuel source (typically renewable, or storage)

- Direct control of DER dispatch or inverter response
- The inverter impact modifying fault current

System operators that have relatively small quantities of DER embedded within their system currently see very little direct impact as the variations observable at the BPS level are minor. On the other hand, where there are high penetrations of DER, the system operator must consider the significant impacts on the ability to accurately forecast and control its system. The system operator must have adequate "situational awareness" and sufficient ERS levels to control the system reliably under all circumstances.

As seen in California, the growth in volume and diversity of DER will require some expanded coordination arrangements and functional capabilities on the part of the distribution utilities and the BPS operator. The NERC ERS effort should continue to monitor these developments addressing T-D interface issues and needs of the BPS.

Appendix C: Review of Existing NERC Standards

As stated in the report, the DERTF has reviewed the list of standards below. The flow of information relating to DER from distribution entities to Transmission Owner/Operator and planning entities is already captured in these Reliability Standards (with the necessary adjustments to MOD-032 as noted in the report) and accounts for the impacts of DER on the T-D interface in planning and operations processes.

BAL-001 Real Power Balancing Control Performance

BAL-002 Disturbance Control Performance

BAL-003 Frequency Response and Frequency Bias Setting

BAL-005 Automatic Generation Control

CIP-002 Cyber Security – BES Cyber System Categorization

CIP-003 Cyber Security – Security Management Controls

CIP-005 Cyber Security – Electronic Security Perimeters

CIP-006 Cyber Security – Physical Security of BES Cyber Systems

CIP-008 Cyber Security – Incident Reporting and Response Planning

CIP-009 Cyber Security – Recovery Plans for BES Cyber Systems

CIP-010 Cyber Security – Configuration Change Management and Vulnerability Assessments

EOP-005 System Restoration Plans

EOP-011 Emergency Operations

FAC-001 Facility Interconnection Requirements

FAC-002 Facility Interconnection Studies

FAC-008 Facility Ratings

FAC-010 System Operating Limits Methodology for the Planning Horizon

FAC-011 System Operating Limits Methodology for the Operations Horizon

FAC-013 Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon

IRO-004 Reliability Coordination – Operations Planning

IRO-005 Reliability Coordination – Current Day Operations

IRO-010 Reliability Coordinator Data Specification and Collection

MOD-001 Available Transmission System Capability

MOD-004 Capacity Benefit Margin

MOD-008 Transmission Reliability Margin Calculation Methodology

MOD-010-0 Steady State Data for Modeling and Simulation of Interconnected Transmission System

MOD-012-0 Dynamics Data for Modeling and Simulation of the Interconnected Transmission System

MOD-016-1.1 Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management

MOD-017-0.1 Aggregated Actual and Forecast Demands and Net Energy for Load

MOD-019-0.1 Reporting of Interruptible Demands and Direct Control Load Management

MOD-020-0 Providing Interruptible Demands and Direct Load Control Management Data to System Operators and Reliability Coordinators

MOD-021-1 Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts

MOD-025 Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

MOD-026 Verification of Models and Data for Generator Excitation Control System and Plant Volt/VAR Control Functions

MOD-027 Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

MOD-028 Area Interchange Methodology

MOD-031 Demand and Energy Data

MOD-032 Data for Power System Modeling and Analysis (replaces MOD-010)

MOD-033 Steady-State and Dynamic System Model Validation (replaces MOD-012)

PRC-004 Protection System Misoperation Identification and Correction

PRC-006 Automatic Under frequency Load Shedding

PRC-008 Implementation and Documentation of Under frequency Load Shedding Equipment Maintenance Program

PRC-010 Under voltage Load Shedding

PRC-011 Under voltage Load Shedding System Maintenance and Testing

PRC-018 Disturbance Monitoring Equipment Installation and Data Reporting

PRC-019 Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls and Protection

PRC-020 Under-Voltage Load Shedding Program Database

PRC-021 Under-Voltage Load Shedding Program Data

PRC-022 Under-Voltage Load Shedding Program Performance

PRC-024-2 (pending) Generator Voltage and Frequency Protective Relay Settings

PRC-027 Coordination of Protection Systems for Performance During Faults

TOP-001 Transmission Operations

TOP-002 Operations Planning

TOP-003 Operational Reliability Data

TOP-004 Transmission Operations

TOP-005 Operational Reliability Information

TPL-001 Transmission System Planning Performance Requirements

VAR-001 Voltage and Reactive Control

VAR-002 Generator Operation for Maintaining Network Voltage Schedules

Appendix D: Transmission-Distribution Interface

As noted in Chapter 1, demand side management (DSM) resources can affect the aggregate characteristics, modeling requirements, and potential BPS reliability impacts at the T-D interface. While DSM activities may not have the same characteristics or behaviors as resources that produce electricity, DSM activities can have impacts at the T-D interface that overlap and interact with those of DER.

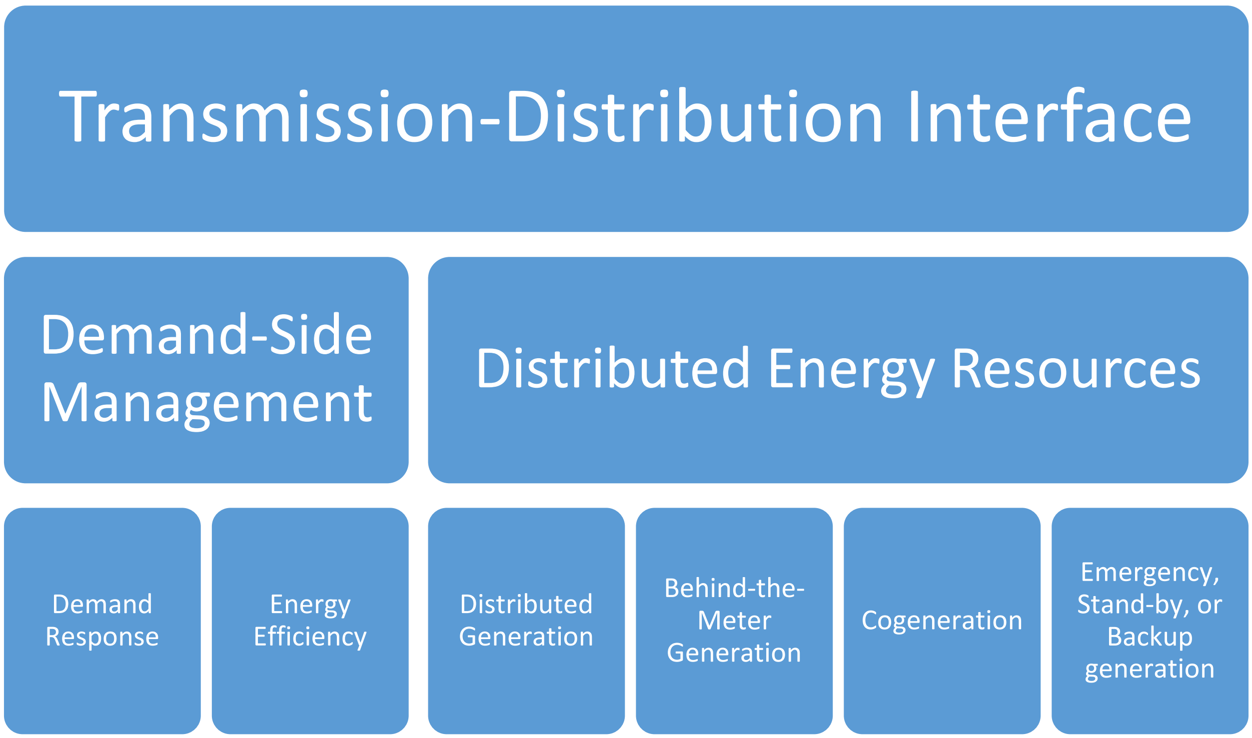


Figure D.1: Relationship Between DSM Resources and DER at the T-D Interface

Task Force Membership

Name	Entity
Gerald Beckerle	Ameren
Dave Canter	American Electric Power
Jim Fletcher	American Electric Power
Richard Hydzik	Avista Corporation
Clyde Loutan	California Independent System Operator
Lorenzo Kristov	California Independent System Operator
Brant Werts	Duke Energy
John Hughes	Electricity Consumers Resource Council
Robert Entriken	Electric Power Research Institute
Aidan Tuohy	Electric Power Research Institute
Jens Boemer	Electric Power Research Institute
Jack Cashin	Electric Power Supply Association
Julia Matevosyan	Electric Reliability Council of Texas
Alfred Corbett	Federal Energy Regulatory Commission
Hassan Hamdar	Florida Reliability Coordinating Council
Jason McDowell	General Electric
Nicholas Miller	General Electric
Sasoon Assaturian	Independent Electricity System Operator
John Simonelli	Independent System Operator of New England
Patricia Poli	Michigan Public Service Commission
Mike McMullen	MISO
Barry Mather	National Renewable Energy Laboratory (NREL)
Paul McCurley	National Rural Electric Cooperative Association
Mark Ahlstrom	NextEra Energy
Robert Cummings	North American Electric Reliability Corporation
Michelle Marx	North American Electric Reliability Corporation
John Moura	North American Electric Reliability Corporation
Ryan Quint	North American Electric Reliability Corporation
Pooja Shah	North American Electric Reliability Corporation
Elliott Nethercutt	North American Electric Reliability Corporation
Thomas Coleman	North American Electric Reliability Corporation
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Quoc Le	Northeast Power Coordinating Council
Gary Keenan	Northwest Power Pool
Dariush Shirmohammadi	California Wind Energy Association
Todd Lucas	Southern Company
Sylvester Toe	Southern Company
Thomas Siegrist	Stone, Mattheis, Xenopoulos & Brew, P.C.
Jagan Mandavilli	Texas Reliability Entity
Brian Evans-Mongeon	Utility Services
Charlie Smith	Utility Variable-Generation Integration Group
Anthony Jankowski	WE Energies
Layne Brown	Western Electricity Coordinating Council

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Proposed Rules

Federal Register

Vol. 81, No. 235

Wednesday, December 7, 2016

DEPARTMENT OF ENERGY

10 CFR Part 205

RIN 1901–AB40

Grid Security Emergency Orders: Procedures for Issuance

AGENCY: Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy.

ACTION: Notice of proposed rulemaking and request for comment.

SUMMARY: The U.S. Department of Energy is proposing to issue procedural regulations concerning the Secretary of Energy's issuance of an emergency order following the President's declaration of a Grid Security Emergency, under the Federal Power Act, as amended. The proposed procedures, if adopted, are intended to ensure the expeditious issuance of emergency orders under the Federal Power Act.

DATES: Public comment on this proposed rule will be accepted until February 6, 2017.

ADDRESSES: You may submit comments, identified by RIN 1901–AB40, by any of the following methods:

1. Follow the instructions for submitting comments on the Federal eRulemaking Portal at *http://www.regulations.gov.*
2. Send email to *oeregs@hq.doe.gov.* Include RIN 1901–AB40 in the subject line of the email. Please include the full body of your comments in the text of the message or as an attachment.
3. Address postal mail to U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability, Mailstop OE–20, Room 8G–017, 1000 Independence Avenue SW., Washington, DC 20585.

Due to potential delays in the delivery of postal mail, we encourage respondents to submit comments electronically to ensure timely receipt.

This notice of proposed rulemaking, and any comments that DOE receives will be made available on regulations.gov. You may request a hardcopy of the comments be sent to you via postal mail by contacting *oeregs@hq.doe.gov* or the DOE's Office of Electricity Delivery and Energy Reliability at Mailstop OE–20, Room 8G–017, 1000 Independence Avenue SW., Washington, DC 20585.

FOR FURTHER INFORMATION CONTACT: Jeffrey Baumgartner, (202) 586–1411; U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability, Mailstop OE–20, Room 8G–017, 1000 Independence Avenue SW., Washington, DC 20585; or *oeregs@hq.doe.gov.*

SUPPLEMENTARY INFORMATION:

Table of Contents

I. Introduction and Background

On December 4, 2015, the President signed into law the Fixing America's Surface Transportation Act (''FAST Act'' or ''The Act''), Public Law 114–94. The Act contains several provisions designed to protect and enhance the Nation's electric power delivery infrastructure. Section 61003 of the Act adds a new section 215A, titled ''Critical Electric Infrastructure Security,'' to Part II of the Federal Power Act, codified at 16 U.S.C. 824o–1. New section 215A(a) defines, among other terms, a ''grid security emergency.'' New section 215A(b) authorizes the Secretary of Energy to order emergency measures after the President declares a grid security emergency. A grid security emergency could result from a physical attack, a cyber-attack using electronic communication or an electromagnetic pulse (EMP), or a geomagnetic storm event, damaging certain electricity infrastructure assets and impairing the reliability of the Nation's power grid. Emergency orders responding to grid security emergencies would aim to mitigate or eliminate threats to reliability as quickly and efficiently as possible. The statute authorizes the Secretary of Energy to issue orders for emergency measures as are necessary, in the Secretary's judgment, to protect or restore the reliability of critical electric infrastructure or defense critical electric infrastructure during the emergency. Critically, the Department's centralized direction following a declared grid security emergency will help the Department to coordinate resources efficiently to minimize the impact of the emergency.

The authority granted in section 215A of the Federal Power Act supplements the Secretary's existing authority, under section 202(c) of the Federal Power Act, to order temporary emergency measures if the Secretary finds ''that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes,'' that the Secretary believes ''will best meet the emergency and serve the public interest.'' To that end, the Secretary may issue orders under section 202(c) requiring the ''temporary connections of facilities[,] generation, delivery, interchange, or transmission of electric energy.''

The FAST Act also directs the Secretary, ''after notice and opportunity for comment,'' to ''establish rules of procedure that ensure that such authority can be exercised expeditiously.'' To ensure that stakeholders and the public understand how the Department would issue an order responding to a grid security emergency, the Department proposes in this notice of proposed rulemaking the procedures it would expect to follow in the event of such emergency. DOE proposes to add these procedures to the existing subpart W in 10 CFR part 205.

Synopsis of the Notice of Proposed Rulemaking

A. General

Both natural and artificial events can disrupt the Nation's power grid. Geomagnetic storm events are unavoidable natural phenomena, and an event of sufficient strength could compromise the grid. EMPs pose another significant threat. Cyber- and physical attacks on infrastructure could also damage or disrupt critical grid components. The Department is committed to minimizing any disruptions from an attack on, or natural damage to, the Nation's power grid. Responses to grid disruptions will need to be tailored to the particular circumstances, and the Department now has the authority to respond as necessary to mitigate the effects of a grid security emergency.

If the President should declare a grid security emergency, the Department intends to follow the procedures established in this rulemaking proceeding. The Secretary is authorized to issue emergency orders ''[w]henever the President issues and provides to the Secretary [of Energy] a written directive or determination identifying a grid security emergency.'' The purpose of an emergency order is to designate ''emergency measures as are necessary in the judgment of the Secretary to protect or restore the reliability of critical electric infrastructure or of defense critical electric infrastructure during such emergency.''

B. Definitions

The proposed rule begins with definitions of key terms in § 205.380. Further explanations for certain definitions and terms appear below.

''Bulk-power system'' encompasses the facilities used to transmit electricity and energy needed to maintain the reliability of that system of interconnected facilities—in essence, the electric power grid for which the President might declare a grid security emergency and authorize the Secretary to issue emergency orders to protect or restore its reliability. The term excludes facilities used in local electric distribution. This definition is drawn from the statutory definition applicable throughout section 215A of the Federal Power Act.

''Commission'' refers to the Federal Energy Regulatory Commission, which is responsible for approving applicable reliability standards. This term does not apply here to State regulatory commissions or to the former Federal Power Commission.

''Electric Reliability Organization'' refers to the organization, certified by the Commission under section 215(c) of the Federal Power Act, which establishes and enforces reliability standards with Commission oversight. As of this rulemaking, the Commission's designated Electric Reliability Organization is the North American Electric Reliability Corporation (NERC).

''Electricity Information Sharing and Analysis Center'' (E–ISAC) refers to the organization, operated on behalf of the electricity subsector by the North American Electric Reliability Corporation, that gathers and analyzes security information, coordinates incident management, and communicates mitigation strategies with stakeholders within the electricity subsector, across interdependent sectors, and with government partners. E–ISAC is one of the organizations with which the Secretary will consult, to the extent practicable, in issuing an emergency order.

The ''Electricity Subsector Coordinating Council'' (ESCC) refers to the organization that aims to foster and facilitate the coordination of sector-wide, policy-related activities and initiatives designed to improve the reliability and resilience of the electricity subsector, including physical and cyber security infrastructure. The ESCC is another of the organizations with which the Secretary will consult, to the extent practicable, in issuing an emergency order. DOE considers the ''electricity subsector'' to include commercial and industrial actors who generate and deliver electric power, along with the facilities those actors use to generate and deliver the power.

An ''Electromagnetic pulse'' is one (1) or more pulses of electromagnetic energy emitted by a device capable of disabling or disrupting operation of, or destroying, electronic devices or communications networks, including hardware, software, and data, by means of such a pulse. The pulse can be accidental, incidental, or malicious.

The ''Emergency & Incident Management Council'' (EIMC) is the organization, internal to the Department and chaired by the Deputy Secretary of Energy, designed to increase cooperation and coordination across the Department to prepare for, mitigate, respond to, and recover from emergencies. The EIMC plays a central role in Grid Security Emergency orders, as it will meet, if practicable, after the President declares the emergency to prepare recommendations to the Secretary.

''Geomagnetic storm'' refers to a temporary disturbance of the Earth's magnetic field resulting from solar activity. These natural phenomena are sometimes powerful enough to disrupt the Bulk-power system. If the disruption is sufficiently severe, a Grid Security Emergency could result.

''Regional entity'' refers to organizations responsible for enforcing reliability standards for the Bulk-power system in certain, defined regions. These organizations operate under NERC and Commission oversight.

C. Summary of Proposed Rule

As described in proposed § 205.381, orders issued under section 215A(b) of the Federal Power Act may apply to the pertinent Electric Reliability Organization (NERC, as of this rulemaking), regional entity, or ''any owner, user, or operator of critical electric infrastructure or of defense critical electric infrastructure within the United States.''

The procedures are designed to allow the Secretary to address a declared grid security emergency. The statute authorizes the Secretary to order response measures that the Secretary believes are necessary to protect or restore the reliability of certain infrastructure in a grid security emergency. Because the nature of a grid security emergency is uncertain, the procedures allow for flexibility in response measures and, as the statute requires, to ''ensure that such authority can be exercised expeditiously.'' While the procedures are expected to produce the most efficient and effective emergency response possible under the circumstances, the Secretary has final authority to issue appropriate grid security emergency orders.

In the event of a grid security emergency, DOE will immediately activate its unified command structure and coordinate outreach efforts. DOE expects that the EIMC will anchor the Department's proposed response via its recommendations to the Secretary. Based on the nature and timing of the emergency, however, the Secretary would maintain discretion, based on a judgment of the relevant circumstances, to issue an emergency order without EIMC input. To the extent practicable, DOE will promptly alert stakeholders of the grid security emergency through existing alert mechanisms, such as the NERC alert system and ESCC communication coordination processes.

Proposed § 205.382 outlines the EIMC procedures. When the Department is notified, in writing, that the President has declared a grid security emergency and has directed the Secretary to order emergency response measures, the EIMC will be activated. The EIMC will create ad hoc task groups, assign recommendation development tasks to these groups, and coordinate the Department's consultation efforts. The EIMC may take other actions but only as necessary and practicable to develop the Department's recommendations to the Secretary. After the EIMC makes its recommendations, the Secretary will issue the emergency order. Again, the Department would follow these procedures to the extent practicable, but subject to the Secretary's judgment of the urgency of the situation and the best approach under the circumstances.

Consistent with the Department's longstanding practice, all reasonable efforts will be made to consult with stakeholders prior to the issuance of an emergency order. The statute also requires the Secretary to consult with other governmental authorities and non-governmental entities before issuing emergency orders, ''to the extent practicable in light of the nature of the grid security emergency and the urgency of the need for action.'' The Department understands that electric reliability entities and private industry will likely be impacted by the emergency and have important situational awareness to assist the Department in identifying mitigation or protection measures. Proposed § 205.383 outlines how the Department will coordinate its communication with other entities. Within the Department, the Office of Electricity Delivery and Energy Reliability (OE) will be the lead program office supporting the Secretary in issuing grid security emergency orders. As set forth in this proposed rule, OE would be responsible for conducting the required consultations under the statute. Consultation would include the Department's effort to obtain information and recommended emergency measures from those government entities,[1] electric reliability entities, and owners, users, or operators of critical electric infrastructure or of defense critical electric infrastructure—including private-sector entities—impacted by the emergency. Historically, the Department has collaborated with other Federal agencies in an energy emergency to obtain waivers or special permits to facilitate expedited restoration. Here, the Department also intends to work with other Federal agencies to obtain waivers or special permits necessary to comply with the Secretary's order.

After the Secretary issues an emergency order, the Department will communicate the order's content to the entities subject to the order, as noted in proposed § 205.384. The Department will also enlist the ESCC and E–ISAC to communicate the order's content to those affected. The Department will also use any other form of communication most appropriate under the circumstances. Optimal communication on grid security emergencies will be paramount during the emergency, and the Department will work to ensure that information is shared that will help it to respond most effectively. For that reason, according to proposed § 205.384 and consistent with obligations to protect classified information, the Secretary may declassify information eligible for that change in status to ensure maximum distribution of information critical to the emergency response.

This proposed rule is limited to the Department's procedures for issuing an emergency order in response to a grid security emergency. Should the Secretary issue such an order, the order itself would set out the requirements and procedures for impacted entities to seek clarification or reconsideration of that particular order. Proposed § 205.385 provides general requirements for such requests. In particular, DOE proposes that anyone subject to a particular order may submit a request for clarification or reconsideration in writing to the Secretary. The requests would be posted on the Department's Web site consistent with criteria established for treatment of critical electric infrastructure information. In acting on a request for clarification or reconsideration, the Secretary may grant or deny the request or may abrogate or modify the final order, in whole or in part, with or without further proceedings, as soon as practicable. Such a request would not stay an emergency order unless the Secretary so determined.

As warranted, and to the extent practicable and consistent with obligations to protect classified information, the Secretary may allow key personnel of ordered entities temporary access to classified information. Proposed § 205.386 sets out this approach.

Proposed § 205.387 describes termination of grid security emergency orders. An emergency order remains effective for up to fifteen (15) days and may be extended for subsequent periods of up to 15 days if the President issues another directive to the Secretary that the original emergency has not ended or that the emergency measures already ordered are still required. If warranted, the Secretary may also terminate an order before the 15 days have elapsed. The entity or entities subject to the emergency order may also request that the Secretary terminate an order if the entity or entities believes that the grid security emergency ceases to exist and that protection or restoration of the grid has been achieved.

The Department also plans to determine compliance with grid security emergency orders, as described in proposed § 205.388. At the time the Department issues an emergency order, or shortly after the issuance, the Department may require the ordered party to provide a detailed account of compliance actions. As noted in proposed § 205.389, enforcement provisions in Part III of the Federal Power Act also apply to orders issued under section 215A. *See* 42 U.S.C. 7151(b) & 7172(a)(2)(A). For appeal purposes, as noted in proposed § 205.390, the Federal Power Act includes the requirements for a rehearing request and the process for an appeal of a decision.

As indicated in proposed § 205.391, the Department will not adjudicate cost recovery under an emergency order, as that determination is reserved for the Commission, state regulators, or the United States Court of Federal Claims. Specifically, the FAST Act allows the Commission to ''establish a mechanism'' allowing an aggrieved party to recover costs, but only if it determines that such a party has ''incurred substantial costs to comply with an order for emergency measures issued under [section 215A] and that such costs were prudently incurred and cannot reasonably be recovered through regulated rates or market prices for the electric energy or services sold by'' the aggrieved party.

Finally, the FAST Act shields parties affected by emergency orders from liability for what would otherwise be violations of the Federal Power Act or the reliability standards, except in cases of gross negligence. New section 215A(f) of the Federal Power Act states that any action or omission taken to comply with an emergency order that causes noncompliance ''with any rule, order, regulation, or provision'' of the Federal Power Act, as well as any FERC-approved reliability standard, ''shall not be considered a violation'' of that legal requirement. The same subsection incorporates the liability protection for emergency orders issued under section 202(c) of the Federal Power Act. That protection, for actions or omissions resulting in noncompliance with ''any Federal, State, or local environmental law or regulation,'' not only frees the ordered party from violations of those laws or regulations, but also shields the

[1] DOE notes that the regulatory text of proposed § 205.383 discusses consultation with agencies supporting Emergency Support Function (ESF) #12. For clarification, ESF #12 is the Department of Energy's responsibility to help reestablish damaged energy systems and components when an incident requires a coordinated Federal response. The scope of ESF #12 includes providing technical expertise; collecting, evaluating, and sharing information on energy system damage; estimating the impact of system outages locally, regionally, and nationally; helping government and private sector entities overcome challenges in reestablishing energy system; and providing information about the status of energy reestablishment efforts.

ordered party from ''any requirement, civil or criminal liability, or a citizen suit under such environmental law or regulation,'' even if a court subsequently stays, modifies, or sets aside the order. Proposed § 205.392 describes all of these protections.

III. Public Participation

A. Submission of Comments

DOE will accept comments, data, and information regarding this proposed rule before or after the public meeting, but no later than the date provided in the **DATES** section at the beginning of this proposed rule. Interested parties may submit comments using any of the methods described in the **ADDRESSES** section at the beginning of this proposed rule.

Submitting comments via *regulations.gov*. The *regulations.gov* Web page will require you to provide your name and contact information. Your contact information will be viewable to DOE Building Technologies staff only. Your contact information will not be publicly viewable except for your first and last names, organization name (if any), and submitter representative name (if any). If your comment is not processed properly because of technical difficulties, DOE will use this information to contact you. If DOE cannot read your comment due to technical difficulties and cannot contact you for clarification, DOE may not be able to consider your comment.

However, your contact information will be publicly viewable if you include it in the comment or in any documents attached to your comment. Any information that you do not want to be publicly viewable should not be included in your comment, nor in any document attached to your comment. Persons viewing comments will see only first and last names, organization names, correspondence containing comments, and any documents submitted with the comments.

Do not submit to *regulations.gov* information for which disclosure is restricted by statute, such as trade secrets and commercial or financial information (hereinafter referred to as Confidential Business Information (CBI)). Comments submitted through *regulations.gov* cannot be claimed as CBI. Comments received through the Web site will waive any CBI claims for the information submitted. For information on submitting CBI, see the Confidential Business Information section.

DOE processes submissions made through *regulations.gov* before posting. Normally, comments will be posted within a few days of being submitted. However, if large volumes of comments are being processed simultaneously, your comment may not be viewable for up to several weeks. Please keep the comment tracking number that *regulations.gov* provides after you have successfully uploaded your comment.

Submitting comments via email, hand delivery, or mail. Comments and documents submitted via email, hand delivery, or mail also will be posted to *regulations.gov*. If you do not want your personal contact information to be publicly viewable, do not include it in your comment or any accompanying documents. Instead, provide your contact information on a cover letter. Include your first and last names, email address, telephone number, and optional mailing address. The cover letter will not be publicly viewable as long as it does not include any comments.

Include contact information each time you submit comments, data, documents, and other information to DOE. If you submit via mail or hand delivery, please provide all items on a CD, if feasible. It is not necessary to submit printed copies. No facsimiles (faxes) will be accepted.

Comments, data, and other information submitted to DOE electronically should be provided in PDF (preferred), Microsoft Word or Excel, WordPerfect, or text (ASCII) file format. Provide documents that are not secured, written in English and free of any defects or viruses. Documents should not contain special characters or any form of encryption and, if possible, they should carry the electronic signature of the author.

Campaign form letters. Please submit campaign form letters by the originating organization in batches of between 50 to 500 form letters per PDF or as one form letter with a list of supporters' names compiled into one or more PDFs. This reduces comment processing and posting time.

Confidential Business Information. According to 10 CFR 1004.11, any person submitting information that he or she believes to be confidential and exempt by law from public disclosure should submit via email, postal mail, or hand delivery two well-marked copies: One copy of the document marked confidential including all the information believed to be confidential, and one copy of the document marked non-confidential with the information believed to be confidential deleted. Submit these documents via email or on a CD, if feasible. DOE will make its own determination about the confidential status of the information and treat it according to its determination.

Factors of interest to DOE when evaluating requests to treat submitted information as confidential include: (1) A description of the items; (2) whether and why such items are customarily treated as confidential within the industry; (3) whether the information is generally known by or available from other sources; (4) whether the information has previously been made available to others without obligation concerning its confidentiality; (5) an explanation of the competitive injury to the submitting person which would result from public disclosure; (6) when such information might lose its confidential character due to the passage of time; and (7) why disclosure of the information would be contrary to the public interest.

It is DOE's policy that all comments may be included in the public docket, without change and as received, including any personal information provided in the comments (except information deemed to be exempt from public disclosure).

IV. Regulatory Review

A. Executive Order No. 12,866

This proposed rule has been determined to be a significant regulatory action under Executive Order No. 12,866, ''Regulatory Planning and Review,'' 58 FR 51,735 (Oct. 4, 1993). Accordingly, this action was subject to review under that Executive Order by the Office of Information and Regulatory Affairs of the Office of Management and Budget.

B. National Environmental Policy Act

DOE has determined that this proposed rule is covered under the Categorical Exclusion found in the DOE's National Environmental Policy Act regulations at paragraph A6 Rulemakings, procedural of appendix A to subpart D, 10 CFR part 1021, which applies to Rulemakings that are strictly procedural, such as rulemaking (under 48 CFR part 9) establishing procedures for technical and pricing proposals and establishing contract clauses and contracting practices for the purchase of goods and services, and rulemaking (under 10 CFR part 600) establishing application and review procedures for, and administration, audit, and closeout of, grants and cooperative agreements. Accordingly, neither an environmental assessment nor an environmental impact statement is required.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) requires preparation of an initial regulatory flexibility analysis for any rule that by law must be proposed for public comment, unless the agency certifies that the rule, if promulgated, will not have a significant economic impact on a substantial number of small entities. As required by Executive Order No. 13,272, ''Proper Consideration of Small Entities in Agency Rulemaking,'' 67 FR 53,461 (Aug. 16, 2002), DOE published procedures and policies on February 19, 2003, to ensure that the potential impacts of its rules on small entities are properly considered during the rulemaking process (68 FR 7990). DOE's procedures and policies are available on the Office of General Counsel's Web site: *http://www.energy.gov/gc/downloads/executive-order-13272-consideration-small-entities-agency-rulemaking.*

DOE has reviewed this proposed rule under the provisions of the Regulatory Flexibility Act and the procedures and policies published on February 19, 2003. This proposed rule sets forth procedures that DOE expects to use to issue an order in the event of a declared grid security emergency. The procedures govern DOE activities in the issuance of an order and therefore impact DOE, a Federal agency, rather than any small entities.

DOE further expects that these orders would be issued rarely. In addition, the FAST Act authorizes DOE to issue orders only to specific entities—namely, the pertinent Electric Reliability Organization (NERC, as of this rulemaking), regional entity, or any owner, user or operator of critical energy infrastructure or defense critical energy infrastructure. DOE has determined that these entities most likely fall under NAICS code 221121, ''Electric Bulk Power Transmission and Control.'' To be considered a small entity, these businesses must have 500 employees or less. Due to the nature of the orders to protect or restore and/or infrastructure, DOE has determined that it is likely to consult with large businesses.

An entity subject to an order may request the clarification or rehearing of an order, or the termination of an order. DOE does not expect that these provisions, which would help an entity to understand an order or, in the case of a termination granted by the Secretary, end the applicability of an order, to impose a significant impact on any entity. DOE may also consult with any of these entities to understand the grid security emergency and obtain recommendations to address the emergency. DOE also does not expect these consultations to result in a significant impact on any entity because the interaction would not order the entity to perform any action, but would rather be an exchange of information to help DOE understand the emergency and consider measures to protect and/or restore infrastructure. In addition, it is likely that only entities with equities that could be impacted by potential orders would be consulted. In the event that an order is issued to address a grid security emergency, because the contents of any order would be highly dependent upon the nature of the grid security emergency, DOE again emphasizes that the order itself, rather than these procedures, would specify the requirements necessary to address the grid security emergency.

On the basis of the foregoing, DOE certifies that this proposed rule will not have a significant economic impact on a substantial number of small entities. Accordingly, DOE has not prepared a regulatory flexibility analysis for this rulemaking. DOE's certification and supporting statement of factual basis will be provided to the Chief Counsel for Advocacy of the Small Business Administration pursuant to 5 U.S.C. 605(b).

D. Paperwork Reduction Act

This proposed rule does not contain information collection requirements subject to approval by the Office of Management and Budget pursuant to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*) and the procedures implementing that Act at 5 CFR part 1320. A person is not required to respond to a collection of information unless it displays a currently valid OMB control number.

E. Unfunded Mandates Reform Act of 1995

The Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4) generally requires Federal agencies to examine closely the impacts of regulatory actions on State, local, and tribal governments. Section 101(5) of title I of that law defines a Federal intergovernmental mandate to include any regulation that would impose upon State, local, or tribal governments an enforceable duty, except a condition of Federal assistance or a duty arising from participating in a voluntary federal program. Title II of that law requires each Federal agency to assess the effects of Federal regulatory actions on State, local, and tribal governments, in the aggregate, or to the private sector, other than to the extent such actions merely incorporate requirements specifically set forth in a statute. Section 202 of that title requires a Federal agency to perform a detailed assessment of the anticipated costs and benefits of any rule that includes a Federal mandate which may result in costs to State, local, or tribal governments, or to the private sector, of $100 million or more in any one year (adjusted annually for inflation). 2 U.S.C. 1532(a) and (b). Section 204 of that title requires each agency that proposes a rule containing a significant Federal intergovernmental mandate to develop an effective process for obtaining meaningful and timely input from elected officers of State, local, and tribal governments. 2 U.S.C. 1534.

This proposed rule will establish the procedures DOE expects to use issue an order in the event of a declared grid security emergency. In the event that an order is issued to address a grid security emergency, the order itself, rather than these procedures, would specify the requirements necessary to address the grid security emergency. The proposed rule will not result in the expenditure by State, local, and tribal governments in the aggregate, or by the private sector, of $100 million or more in any one year. Accordingly, no assessment or analysis is required under the Unfunded Mandates Reform Act of 1995.

F. Treasury and General Government Appropriations Act, 1999

Section 654 of the Treasury and General Government Appropriations Act, 1999 (Pub. L. 105–277) requires Federal agencies to issue a Family Policymaking Assessment for any proposed rule that may affect family well-being. The proposed rule will not have any impact on the autonomy or integrity of the family as an institution. Accordingly, DOE has concluded that it is not necessary to prepare a Family Policymaking Assessment.

G. Executive Order No. 13,132

Executive Order No. 13,132, ''Federalism,'' 64 FR 43,255 (Aug. 4, 1999) imposes certain requirements on agencies formulating and implementing policies or regulations that preempt State law or that have federalism implications. Agencies are required to examine the constitutional and statutory authority supporting any action that would limit the policymaking discretion of the States and carefully assess the necessity for such actions. DOE has examined this proposed rule and has determined that it will not preempt State law and will not have a substantial direct effect on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government. This proposed rule would establish the procedures DOE expects to use issue an order in the event of a declared grid security emergency. In the event that an order is issued to address a grid security emergency, the order itself, rather than these procedures, would specify the requirements necessary to address the grid security emergency. No further action is required by Executive Order No. 13,132.

H. Executive Order No. 12,988

With respect to the review of existing regulations and the promulgation of new regulations, section 3(a) of Executive Order No. 12,988, ''Civil Justice Reform,'' 61 FR 4729 (Feb. 7, 1996), imposes on Executive agencies the general duty to adhere to the following requirements: (1) Eliminate drafting errors and ambiguity; (2) write regulations to minimize litigation; and (3) provide a clear legal standard for affected conduct rather than a general standard and promote simplification and burden reduction. With regard to the review required by section 3(a), section 3(b) of Executive Order No. 12,988 specifically requires that Executive agencies make every reasonable effort to ensure that the regulation: (1) Clearly specifies the preemptive effect, if any; (2) clearly specifies any effect on existing Federal law or regulation; (3) provides a clear legal standard for affected conduct while promoting simplification and burden reduction; (4) specifies the retroactive effect, if any; (5) adequately defines key terms; and (6) addresses other important issues affecting clarity and general draftsmanship under any guidelines issued by the Attorney General. Section 3(c) of Executive Order No. 12,988 requires Executive agencies to review regulations in light of applicable standards in section 3(a) and section 3(b) to determine whether they are met or whether it is unreasonable to meet one or more of them. DOE has completed the required review and determined that, to the extent permitted by law, the proposed rule meets the relevant standards of Executive Order No. 12,988.

I. Treasury and General Government Appropriations Act, 2001

The Treasury and General Government Appropriations Act, 2001 (44 U.S.C. 3516 note) provides for agencies to review most disseminations of information to the public under guidelines established by each agency pursuant to general guidelines issued by OMB.

OMB's guidelines were published at 67 FR 8452 (Feb. 22, 2002), and DOE's guidelines were published at 67 FR 62,446 (Oct. 7, 2002). DOE has reviewed this proposed rule under the OMB and DOE guidelines and has concluded that it is consistent with applicable policies in those guidelines.

J. Executive Order No. 13,211

Executive Order No. 13,211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use,'' 66 FR 28,355 (May 22, 2001) requires Federal agencies to prepare and submit to the OMB a Statement of Energy Effects for any proposed significant energy action. A ''significant energy action'' is defined as any action by an agency that promulgated or is expected to lead to promulgation of a final rule, and that (1) is a significant regulatory action under Executive Order No. 12,866, or any successor order; and (2) is likely to have a significant adverse effect on the supply, distribution, or use of energy, or (3) is designated by the Administrator of OIRA as a significant energy action. For any proposed significant energy action, the agency must give a detailed statement of any adverse effects on energy supply, distribution, or use should the proposal be implemented, and of reasonable alternatives to the action and their expected benefits on energy supply, distribution, and use. This regulatory action will not have a significant adverse effect on the supply, distribution, or use of energy. The proposed rule would establish the procedures DOE expects to use issue an order in the event of a declared grid security emergency. In the event that an order is issued to address a grid security emergency, the order itself, rather than these procedures, would specify the requirements necessary to address the grid security emergency. In addition, the statute requires that the order must ''protect or restore'' critical electric infrastructure or defense critical electric infrastructure. Therefore, the rule is not a significant energy action. Accordingly, DOE has not prepared a Statement of Energy Effects.

V. Approval of the Office of the Secretary

The Secretary of Energy has approved publication of this proposed rule.

List of Subjects in 10 CFR Part 205

Administrative practice and procedure, Energy, and Recordkeeping and reporting requirements.

Issued in Washington, DC, on November 23, 2016.

Patricia Hoffman,

Assistant Secretary, Office of Electricity Delivery and Energy Reliability.

For the reasons stated in the preamble, DOE proposes to amend part 205 of chapter II, subchapter A, of Title 10 of the Code of Federal Regulations, as set forth below:

PART 205—ADMINISTRATIVE PROCEDURES AND SANCTIONS

■ 1. The authority citation for part 205 continues to read as follows:

Authority: Department of Energy Organization Act, Pub. L. 95–91, 91 Stat. 565 (42 U.S.C. Section 7101). Federal Power Act, Pub. L. 66–280, 41 Stat. 1063 (16 U.S.C. Section 792) *et seq.,* Department of Energy Delegation Order No. 0204–4 (42 FR 60726). E.O. 10485, 18 FR 5397, 3 CFR, 1949–1953, Comp., p. 970 as amended by E.O. 12038, 43 FR 4957, 3 CFR 1978 Comp., p. 136.

■ 2. Part 205 is amended by revising the heading of subpart W to read as follows:

Subpart W—Electric Power System Permits and Reports; Applications; Administrative Procedures and Sanctions; Grid Security Emergency Orders

■ 3. Subpart W is amended by adding an undesignated center heading after § 205.379 to read as follows:

* * * * *

Internal Procedures for Issuance of a Grid Security Emergency Order

■ 4. Sections 205.380 through 250.392 are added to subpart W to read as follows:

Sec.
§ 205.380 Definitions.
§ 205.381 Application of emergency order.
§ 205.382 Procedures for issuing an emergency order.
§ 205.383 Outreach and consultation.
§ 205.384 Communication of orders.
§ 205.385 Clarification or reconsideration.
§ 205.386 Temporary access to classified information.
§ 205.387 Termination of an emergency order.
§ 205.388 Tracking compliance.
§ 205.389 Enforcement.
§ 205.391 Cost recovery.
§ 205.392 Liability exemptions.

§ 205.380 Definitions.

As used in this part:

Bulk-power system means:

(1) Facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and

(2) Electric energy from generation facilities needed to maintain transmission system reliability.

(3) The term does not include facilities used in the local distribution of electric energy.

Commission means the Federal Energy Regulatory Commission.

Critical electric infrastructure means a system or asset of the bulk-power system, whether physical or virtual, the incapacity or destruction of which would negatively affect national security, economic security, public health or safety, or any combination of such matters.

Defense critical electric infrastructure means any electric infrastructure located in any of the 48 contiguous States or the District of Columbia that serves a facility designated by the Secretary as:

(1) Critical to the defense of the United States; and

(2) Vulnerable to a disruption of the supply of electric energy provided to such facility by an external provider, but that is not owned or operated by the owner or operator of such facility.

Department means the United States Department of Energy.

Electric reliability organization means the organization, certified by the Commission under section 215(c) of the Federal Power Act, 16 U.S.C. 824o(c), the purpose of which is to establish and enforce reliability standards for the bulk-power system, subject to Commission review.

Electricity information sharing and analysis center means the organization, operated on behalf of the electricity subsector by the Electric Reliability Organization, that gathers and analyzes security information, coordinates incident management, and communicates mitigation strategies with stakeholders within the electricity subsector, across interdependent sectors, and with government partners. The E–ISAC, in collaboration with the Department of Energy and the Electricity Subsector Coordinating Council (ESCC), serves as the primary security communications channel for the electricity subsector and enhances the subsector's ability to prepare for and respond to cyber and physical threats, vulnerabilities, and incidents.

Electricity subsector coordinating council means the organization that aims to foster and facilitate the coordination of sector-wide, policy-related activities and initiatives designed to improve the reliability and resilience of the electricity subsector, including physical and cyber security infrastructure.

Electromagnetic pulse means one or more pulses of electromagnetic energy emitted by a device capable of disabling or disrupting operation of, or destroying, electronic devices or communications networks, including hardware, software, and data, by means of such a pulse.

Emergency & incident management council means the organization, internal to the Department of Energy and chaired by the Deputy Secretary of Energy, designed to increase cooperation and coordination across the Department to prepare for, mitigate, respond to, and recover from emergencies.

Geomagnetic storm means a temporary disturbance of the Earth's magnetic field resulting from solar activity.

Grid security emergency means the occurrence or imminent danger of:

(1) A malicious act using electronic communication or an electromagnetic pulse, or a geomagnetic storm event, that could disrupt the operation of those electronic devices or communications networks, including hardware, software, and data, that are essential to the reliability of critical electric infrastructure or of defense critical electric infrastructure; and

(2) Disruption of the operation of such devices or networks, with significant adverse effects on the reliability of critical electric infrastructure or of defense critical electric infrastructure, as a result of such act or event; or

(3) A direct physical attack on critical electric infrastructure or on defense critical electric infrastructure; and

(4) Significant adverse effects on the reliability of critical electric infrastructure or of defense critical electric infrastructure as a result of such physical attack.

Regional entity means an entity having enforcement authority under section 215(e)(4) of the Federal Power Act, 16 U.S.C. 824o(e)(4).

Secretary means the Secretary of Energy.

§ 205.381 Application of emergency order.

An order for emergency measures under section 215A(b) of the Federal Power Act may apply to the Electric Reliability Organization, a regional entity, or any owner, user, or operator of critical electric infrastructure or of defense critical electric infrastructure within the United States.

§ 205.382 Procedures for issuing an emergency order.

(a) The Secretary has final authority and may act as quickly as necessary to address the emergency. The Secretary will adhere to these procedures unless, in the Secretary's judgment, the emergency requires alternative procedures.

(b) Upon the Department's receipt of the President's written directive or determination identifying a Grid Security Emergency, the Emergency & Incident Management Council (Council) will convene at least one emergency meeting. Resulting from this meeting, the Council's responsibilities will include, but not be limited to:

(1) Assigning consultation and situational awareness tasks;

(2) Creating ad hoc task groups; and

(3) Assigning recommendation development tasks to the ad hoc task groups it has created.

(c) The Council will present its recommendations to the Secretary as expeditiously as possible and practicable. As quickly as the situation requires, following presentation of the Council's recommendations, the Secretary will issue the emergency order.

§ 205.383 Outreach and consultation.

The Department of Energy's Office of Electricity Delivery and Energy Reliability will conduct consultation related to any order issued by the Secretary in response to a declared Grid Security Emergency. Before the issuance of any order, to the extent practicable in light of the nature of the Grid Security Emergency and the urgency of the need for action, outreach efforts will be made to consult at least the following: Authorities in the government of Canada; authorities in the government of Mexico; appropriate Federal agencies including, but not limited to, those supporting Emergency Support Function No. 12; the Commission; and at least the following non-government entities: The Electricity Subsector Coordinating Council, the Electric Reliability Organization, regional entities, and owners, users, or operators of Critical Electric Infrastructure or of Defense Critical Electric Infrastructure within the United States. Consultation will include the Department's effort to obtain information related to the Grid Security Emergency and recommended emergency measures from those governments, electric reliability entities, and private sector companies impacted by the emergency.

§ 205.384 Communication of orders.

The Department will communicate the content of emergency orders issued by the Secretary to the parties subject to the order. The Department will also rely on existing coordinating bodies, such as the Electricity Subsector Coordinating Council and the Electricity Information Sharing and Analysis Center, in addition to any other form or forms of communication most expedient under the circumstances, to communicate the content of emergency orders issued by the Secretary. To the extent practicable under the circumstances, efforts will be made to declassify information to ensure maximum distribution.

§ 205.385 Clarification or reconsideration.

Any request for clarification or reconsideration of an emergency order issued under section 215A(b) of the Federal Power Act must be submitted in writing to the Secretary, and will be posted on the DOE Web site consistent with CEII criteria. The Secretary may, in his sole discretion, order a stay of the emergency order for which such clarification or rehearing is sought. The Secretary may grant or deny the request for clarification or reconsideration, or may abrogate or modify the order, in whole or in part, with or without further proceedings, as soon as practicable.

§ 205.386 Temporary access to classified information.

To the extent practicable, and consistent with obligations to protect classified information, the Secretary may provide temporary access to classified information, related to a Grid Security Emergency for which emergency measures are issued, to key personnel of any entity subject to such emergency measures. The purpose of this access is to enable optimum communication between the entity and the Secretary and other appropriate Federal agencies regarding the Grid Security Emergency.

§ 205.387 Termination of an emergency order.

(a) An order for emergency measures shall expire no later than 15 days after its issuance. The Secretary may reissue an order for emergency measures for subsequent periods, not to exceed 15 days for each such period, provided that the President, for each such period, issues and provides to the Secretary a written directive or determination that the Grid Security Emergency for which the Secretary intends to reissue an emergency order continues to exist or that the emergency measures continue to be required.

(b) The Secretary may rescind an emergency order after finding that the Grid Security Emergency for which that order was issued has ended and that protective or mitigation measures required by the order have been sufficiently taken.

(c) An entity or entities subject to an emergency order under this rule may, at any time, request termination of the emergency order by demonstrating, in a petition to the Secretary, that the emergency no longer exists and that protective or mitigation measures required by the order have been sufficiently taken.

§ 205.388 Tracking compliance.

Beginning at the time the Secretary issues an emergency order, the Department may require the ordered party to provide a detailed account of actions taken to comply with the terms of the order.

§ 205.389 Enforcement.

In accordance with Part III of the Federal Power Act, the Secretary may take or seek enforcement action against ordered parties who fail to comply with the terms of an order issued under section 215A(b) of that Act.

§ 205.390 Rehearing and Judicial Review.

The procedures of Part III of the Federal Power Act apply to motions for rehearing of orders issued under section 215A(b) of that Act filed for the purpose of preserving appellate rights.

§ 205.391 Cost recovery.

A party seeking recovery of costs associated with compliance with an order issued under section 215A(b) of the Federal Power Act must petition the appropriate State regulatory agency, the United States Court of Federal Claims, or the Commission for relief.

§ 205.392 Liability exemptions.

To the extent any action or omission taken by an entity that is necessary to comply with an order for emergency measures issued by authority of section 215A(b) of the Federal Power Act and pursuant to this Part, including any action or omission taken to voluntarily comply with such order, results in noncompliance with, or causes such entity not to comply with any rule, order, regulation, or provision of or under that Act, including any reliability standard approved by the Commission pursuant to section 215 of that Act, such action or omission shall not be considered a violation of such rule, order, regulation, or provision. Further, an action or omission by an owner, operator, or user of Critical Electric Infrastructure or of Defense Critical Electric Infrastructure to comply with an order for emergency measures issued under section 215A(b) of the Federal Power Act shall be treated as an action or omission taken to comply with an order issued under section 202(c) of that Act for purposes of such section. These liability exemptions shall not apply to an entity that, in the course of complying with an order for emergency measures issued under section 215A(b) of the Federal Power Act by taking an action or omission for which the entity would otherwise be liable, takes such action or omission in a grossly negligent manner.

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DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2016–6436; Directorate Identifier 2015–SW–037–AD]

RIN 2120–AA64

Airworthiness Directives; Airbus Helicopters Deutschland GmbH Helicopters

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: We propose to adopt a new airworthiness directive (AD) for Airbus Helicopters Deutschland GmbH (Airbus Helicopters) Model MBB–BK117 C–2 helicopters. This proposed AD would require inspecting the pilot collective wiring harness. This proposed AD is prompted by a report that a heat-shrinkable sleeve prevented the twist grip on the collective from being fully engaged during a flight test. The proposed actions are intended to prevent failure of the hoist or emergency landing gear flotation systems due to chafing of wiring caused by an incorrectly installed heat-shrinkable sleeve.

DATES: We must receive comments on this proposed AD by February 6, 2017.

ADDRESSES: You may send comments by any of the following methods:

- *Federal eRulemaking Docket:* Go to *http://www.regulations.gov.* Follow the online instructions for sending your comments electronically.
- *Fax:* 202–493–2251.
- *Mail:* Send comments to the U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590–0001.
- *Hand Delivery:* Deliver to the ''Mail'' address between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

Examining the AD Docket

You may examine the AD docket on the Internet at *http://www.regulations.gov* by searching for and locating Docket No. FAA–2016–6436; or in person at the Docket

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, 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(s):	Modifications to Geomagnetic Disturbance Standards		
Date Submitted:	December 1, 2016		
SAR Requester Information			
Name:	Frank Koza		
Organization:	PJM Interconnection / Project 2013-03 SDT Chair		
Telephone:	610-666-4228	E-mail:	frank.koza@pjm.com
SAR Type (Check as many as applicable)			
☒ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Purpose (Describe what the standard action will achieve in support of Bulk Electric System reliability.):
The goal of this project is to address the Federal Energy Regulatory Commission (Commission) directives contained in Order No. 830 by modifying **TPL-007-1 - Transmission System Planned Performance for Geomagnetic Disturbance Events** and the benchmark GMD event used in GMD Vulnerability Assessments or by developing an equally efficient and effective alternative.
Industry Need (What is the industry problem this request is trying to solve?):
On September 22, 2016, the Commission issued Order No. 830 approving TPL-007-1. In the order, the Commission directed NERC to develop certain modifications to the Standard, including: • Modify the benchmark GMD event definition used for GMD Vulnerability Assessments; • Make related modifications to requirements pertaining to transformer thermal impact assessments;

SAR Information
• Require collection of GMD-related data, and for NERC to make it publicly available; and • Require deadlines for Corrective Action Plans (CAPs) and GMD mitigating actions. The Commission established a deadline of 18 months from the effective date of Order No. 830 for completing the revisions, which is May 29, 2018.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The Standards Drafting Team (SDT) shall develop modifications to TPL-007-1 and the benchmark GMD event that address Commission directives from Order No. 830. The work will include development of Violation Risk Factors, Violation Severity Levels, and an Implementation Plan for the modified standards within the deadline established by the Commission in Order No. 830.
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 SDT shall address each of the Order No. 830 directives by developing modifications to requirements in TPL-007-1 and related material, or the SDT shall develop an equally efficient and effective alternative. To address concerns identified in Order No. 830, the Commission directed the following: **<u>Benchmark GMD Event</u>** • *[T]he Commission, as proposed in the NOPR, directs NERC to develop revisions to the benchmark GMD event definition so that the reference peak geoelectric field amplitude component is not based solely on spatially-averaged data.(P.44)* • *Without prejudging how NERC proposes to address the Commission's directive, NERC's response to this directive should satisfy the NOPR's concern that reliance on spatially-averaged data alone does not address localized peaks that could potentially affect the reliable operation of the Bulk-Power System. (P.47)* **<u>Transformer Thermal Impact Assessment</u>** • *Consistent with our determination above regarding the reference peak geoelectric field amplitude value, the Commission directs NERC to revise Requirement R6 to require registered entities to apply spatially averaged and non-spatially averaged peak geoelectric field values, or some equally efficient and effective alternative, when conducting thermal impact assessments. (P.65)* **<u>Collection of GMD Data</u>** • *The Commission … adopts the NOPR proposal in relevant part and directs NERC to develop revisions to Reliability Standard TPL-007-1 to require responsible entities to collect GIC monitoring and magnetometer data as necessary to enable model validation and situational awareness, including from any devices that must be added to meet this need. The NERC standard drafting team should address the criteria for collecting GIC monitoring and magnetometer data...*

SAR Information
and provide registered entities with sufficient guidance in terms of defining the data that must be collected.... (P.88) • *Each responsible entity that is a transmission owner should be required to collect necessary GIC monitoring data. However, a transmission owner should be able to apply for an exemption from the GIC monitoring data collection requirement if it demonstrates that little or no value would be added to planning and operations. (P.91)* • *NERC may also propose to incorporate the GIC monitoring and magnetometer data collection requirements in a different Reliability Standard....(P.91)* **<u>Deadlines for Corrective Action Plans and Mitigations</u>** • *The Commission directs NERC to modify Reliability Standard TPL-007-1 to include a deadline of one year from the completion of the GMD Vulnerability Assessments to complete the development of corrective action plans. (P.101)* • *The Commission also directs NERC to modify Reliability Standard TPL-007-1 to include a two-year deadline after the development of the corrective action plan to complete the implementation of non-hardware mitigation and four-year deadline to complete hardware mitigation…. The Commission agrees that NERC should consider extensions of time on a case-by-case basis. (P.102)*

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.
☐	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.

Reliability Functions		
☐	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.

Reliability and Market Interface Principles	
☐	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

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
FRCC	
MRO	
NPCC	
RF	
SERC	
SPP RE	
Texas RE	
WECC	

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

This is the first draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	October 19, 2016
SAR posted for comment	October 20 - November 21, 2016

Anticipated Actions	Date
45-day formal comment period with ballot	January 2017
NERC Board (Board) adoption	August 2017

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): None

Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

A. Introduction

1. **Title:** **Cyber Security - Supply Chain Risk Management**

2. **Number:** **CIP-013-1**

3. **Purpose:** To mitigate cyber security risks to the reliable operation of the Bulk Electric System (BES) by implementing security controls for supply chain risk management of BES Cyber Systems.

4. **Applicability:**

4.1. Functional Entities: For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

4.1.1. Balancing Authority

4.1.2. Distribution Provider that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:

4.1.2.1. Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:

4.1.2.1.1. Is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.1.2.1.2. Performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.1.2.2. Each Remedial Action Scheme (RAS) where the RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.3. Generator Operator

4.1.4. Generator Owner

4.1.5. Reliability Coordinator

4.1.6. Transmission Operator

4.1.7. Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. Is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. Performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each RAS where the RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers

4.2.2.1. All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-013-1:

4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters (ESPs).

4.2.3.3. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. Effective Date: See Implementation Plan.

B. Requirements and Measures

Rationale for Requirement R1:
The proposed Requirement addresses Order No. 829 directives for entities to implement a plan(s) that includes controls for mitigating cyber security risks in the supply chain. The plan(s) is required to address the following four objectives (P. 45):

(1) Software integrity and authenticity;
(2) Vendor remote access;
(3) Information system planning; and
(4) Vendor risk management and procurement controls.

The cyber security risk management plan(s) specified in Requirement R1 apply to BES Cyber Systems and, to the extent applicable, associated Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets.

Implementation of the cyber security risk management plan(s) does not require the Responsible Entity to renegotiate or abrogate existing contracts, consistent with Order No. 829 (P. 36) as specified in the Implementation Plan.

Requirement R1 Part 1.1 addresses Order No. 829 directives for identification and documentation of risks in the planning and development processes related to proposed BES Cyber Systems (P. 56). The objective is to ensure entities consider risks and options for mitigating these risks when planning, acquiring, and deploying BES Cyber Systems.

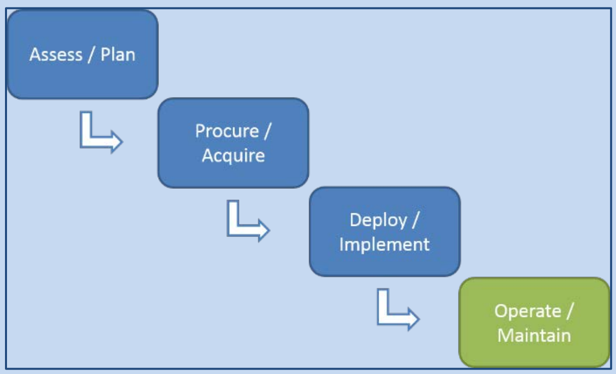
Requirement R1 Part 1.2 addresses Order No. 829 directives for procurement controls to address vendor-related security concepts in future contracts for BES Cyber Systems and, if applicable, associated Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets. (P. 59). The objective of Part 1.2 is for entities to include these topics in their plans so that procurement and contract negotiation processes address the applicable risks. Implementation of elements contained in the entity's plan related to Part 1.2 is accomplished through the entity's procurement and contract negotiation processes. For example, entities can implement the plan by including applicable procurement items from their plan in Requests for Proposals (RFPs) and in negotiations with vendors. Obtaining specific controls in the negotiated contract may not be feasible and is not considered failure to implement an entity's plan.

The objective of verifying software integrity and authenticity (Part 1.2.5) is to ensure that the software being installed in the applicable cyber system was not modified without the awareness of the software supplier and is not counterfeit.

The term *vendors* as used in the standard includes (i) developers or manufacturers of information systems, system components, or information system services; (ii) product resellers; or (iii) system integrators.

Collectively, the provisions of Requirement R1 and R2 address an entity's controls for managing cyber security risks to BES Cyber Systems during the planning, acquisition, and deployment phases of the system life cycle, as shown below.

Notional BES Cyber System Life Cycle



Requirements R3 through R5 address controls for software integrity and authenticity and vendor remote access that apply to the operate/maintain phase of the system life cycle.

R1. Each Responsible Entity shall implement one or more documented supply chain risk management plan(s) that address controls for mitigating cyber security risks to BES Cyber Systems and, if applicable, associated Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets. The plan(s) shall address: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1. The use of controls in BES Cyber System planning and development to:

1.1.1. Identify and assess risk(s) during the procurement and deployment of vendor products and services; and

1.1.2. Evaluate methods to address identified risk(s).

1.2. The use of controls in procuring vendor product(s) or service(s) that address the following items, to the extent each item applies to the Responsible Entity's BES Cyber Systems and, if applicable, associated Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets:

1.2.1. Process(es) for notification of vendor security events;

1.2.2. Process(es) for notification when vendor employee remote or onsite access should no longer be granted;

1.2.3. Process(es) for disclosure of known vulnerabilities;

1.2.4. Coordination of response to vendor-related cyber security incidents;

1.2.5. Process(es) for verifying software integrity and authenticity of all software and patches that are intended for use;

1.2.6. Coordination of remote access controls for (i) vendor-initiated Interactive Remote Access and (ii) system-to-system remote access with a vendor(s); and

1.2.7. Other process(es) to address risk(s) as determined in Part 1.1.2, if applicable.

M1. Evidence shall include (i) one or more documented supply chain cyber security risk management plan(s) that address controls for mitigating cyber security risks as specified in the Requirement; and (ii) documentation to demonstrate implementation of the supply chain cyber security risk management plan(s), which could include, but is not limited to, written agreements in electronic or hard copy format, correspondence, policy documents, or working documents that demonstrate implementation of the cyber security risk management plan(s).

Rationale for Requirement R2:
The proposed requirement addresses Order No. 829 directives for entities to periodically reassess selected supply chain cyber security risk management controls (P. 46).

Order No. 829 also directs that the periodic assessment "ensure that the required plan remains up-to-date, addressing current and emerging supply chain-related concerns and vulnerabilities" (P. 47). Examples of sources of information that the entity considers include guidance or information issued by:

- NERC or the E-ISAC
- ICS-CERT
- Canadian Cyber Incident Response Centre (CCIRC)

R2. Each Responsible Entity shall review and update, as necessary, its supply chain cyber security risk management plan(s) specified in Requirement R1 at least once every 15 calendar months, which shall include: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

2.1. Evaluation of revisions, if any, to address applicable new supply chain security risks and mitigation measures; and

2.2. Obtaining CIP Senior Manager or delegate approval.

M2. Evidence shall include the dated supply chain cyber security risk management plan(s) approved by the CIP Senior Manager or delegate(s) and additional evidence to demonstrate review of the supply chain cyber security risk management plan(s) and evaluation of revisions, if any, to address applicable new supply chain security risks and mitigation measures as specified in the Requirement. Evidence may include, but is not limited to, policy documents, revision history, records of review, or workflow evidence from a document management system that indicate review of supply chain risk management plan(s) at least once every 15 calendar months; and documented approval by the CIP Senior Manager or delegate.

Rationale for Requirement R3:
The proposed requirement addresses Order No. 829 directives for verifying software integrity and authenticity prior to installation in BES Cyber Systems (P. 48).

The objective of verifying software integrity and authenticity is to ensure that the software being installed in the BES Cyber System was not modified without the awareness of the software supplier and is not counterfeit.

R3. Each Responsible Entity shall implement one or more documented process(es) for verifying the integrity and authenticity of the following software and firmware before being placed in operation on high and medium impact BES Cyber Systems: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

3.1. Operating System(s);

3.2. Firmware;

3.3. Commercially available or open-source application software; and

3.4. Patches, updates, and upgrades to 3.1 through 3.3.

M3. Evidence shall include (i) a documented process(es) for verifying the integrity and authenticity of software and firmware before being placed in operation on high and medium impact BES Cyber Systems as specified in the Requirement; and (ii) evidence to show that the process was implemented. This evidence may include, but is not limited to, documentation that the entity performed the actions contained in the process to verify the integrity and authenticity of software and firmware and any patches, updates, and upgrades to software and firmware prior to installation on high and medium impact BES Cyber Systems.

Rationale for Requirement R4:
The proposed requirement addresses Order No. 829 directives for controls on vendor-initiated remote access to BES Cyber Systems covering both user-initiated and machine-to-machine vendor remote access (P. 51). The objective of the Requirement is to mitigate potential risks of a compromise at a vendor from traversing over an unmonitored remote access connection.

The objective of Requirement R4 Part 4.3 is for entities to have the ability to rapidly disable remote access sessions in the event of a system breach as specified in Order No. 829 (P. 52).

R4. Each Responsible Entity shall implement one or more documented process(es) for controlling vendor remote access to high and medium impact BES Cyber Systems. The process(es) shall provide the following for (i) vendor-initiated Interactive Remote Access and (ii) system-to-system remote access with a vendor(s): *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Authorization of remote access by the Responsible Entity;

4.2. Logging and monitoring of remote access sessions to detect unauthorized activity; and

4.3. Disabling or otherwise responding to unauthorized activity during remote access sessions.

M4. Evidence shall include (i) a documented process(es) for controlling vendor remote access as specified in the Requirement; and (ii) evidence to show that the process was implemented. This evidence may include, but is not limited to, documentation of authorization of vendor remote access; hard copy or electronic logs of vendor-initiated Interactive Remote Access and system-to-system remote access sessions; hard copy or electronic listing of alert capabilities applicable to vendor remote access of the BES Cyber System; or records of response to unauthorized vendor remote access.

Rationale for Requirement R5:
The proposed requirement addresses Order No. 829 directives for (i) verifying software integrity and authenticity; and (ii) controlling vendor remote access, as they apply to low impact BES Cyber Systems. (P. 48 and P. 51).

An inventory, list, or discrete identification of low impact BES Cyber Systems or their BES Cyber Assets is not required. Lists of authorized users are not required.

An entity could apply process(es) used for Requirements R3 and R4 to satisfy its obligations in Requirement R5 or could develop a separate policy or process(es) to address low impact BES Cyber Systems.

R5. Each Responsible Entity with at least one asset identified in CIP-002 containing low impact BES Cyber Systems shall have one or more documented cyber security policies, which shall be reviewed and approved by the CIP Senior Manager or delegate at least once every 15 calendar months, that address the following topics for its low impact BES Cyber Systems: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

5.1. Integrity and authenticity of software and firmware and any patches, updates, and upgrades to software and firmware; and

5.2. Controlling vendor-initiated remote access, including system-to-system remote access with vendor(s).

M5. Evidence may include, but is not limited to, policy documents; revision history, records of review, or workflow evidence from a document management system that indicate review of each cyber security policy at least once every 15 calendar months; and documented approval by the CIP Senior Manager or delegate for each cyber security policy.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

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 Responsible 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.

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar 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.

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 implemented one or more documented supply chain risk management plan(s), but the plan(s) did not include one of the elements specified in Parts 1.1 or 1.2.	The Responsible Entity implemented one or more documented supply chain risk management plan(s), but the plan(s) did not include either of the elements specified in Parts 1.1 or 1.2.; OR The Responsible Entity did not implement one or more documented supply chain risk management plan(s) as specified in the Requirement.
R2.	The Responsible Entity reviewed and updated, as necessary, its supply chain cyber security risk management plan(s) and obtained CIP Senior Manager or delegate approval but did so more than 15 calendar months but less than or equal to 16 calendar months	The Responsible Entity reviewed and updated, as necessary, its supply chain cyber security risk management plan(s) and obtained CIP Senior Manager or delegate approval but did so more than 16 calendar months but less than or equal to 17 calendar months	The Responsible Entity reviewed and updated, as necessary, its supply chain cyber security risk management plan(s) and obtained CIP Senior Manager or delegate approval but did so more than 17 calendar months but less than or equal to 18	The Responsible Entity did not review and update, as necessary, its supply chain cyber security risk management plan(s) and obtain CIP Senior Manager or delegate approval within 18 calendar months of the previous review as specified in the Requirement.

	since the previous review as specified in the Requirement.	since the previous review as specified in the Requirement.	calendar months since the previous review as specified in the Requirement.	
R3.	N/A	N/A	N/A	The Responsible Entity did not implement one or more documented process(es) for verifying the integrity and authenticity of software and firmware before being placed in operation on high and medium impact BES Cyber Systems as specified in the Requirement.
R4.	N/A	The Responsible Entity implemented one or more documented process(es) for controlling vendor remote access to high and medium impact BES Cyber Systems, but did not include one of the elements specified in Part 4.1 through Part 4.3.	The Responsible Entity implemented one or more documented process(es) for controlling vendor remote access to high and medium impact BES Cyber Systems, but did not include two of the elements specified in Part 4.1 through Part 4.3.	The Responsible Entity implemented one or more documented process(es) for controlling vendor remote access to high and medium impact BES Cyber Systems, but did not include any of the elements specified in Part 4.1 through Part 4.3; OR, The Responsible Entity did not implement one or more documented process(es) for controlling vendor remote access to high and medium impact BES Cyber Systems as

				specified in the Requirement.
R5.	The Responsible Entity had cyber security policies specified in the requirement that were reviewed and approved by the CIP Senior Manager or delegate, however the approval was more than 15 calendar months but less than or equal to 16 calendar months from the previous review.	The Responsible Entity had cyber security policies specified in the requirement that were reviewed and approved by the CIP Senior Manager or delegate, however the approval was more than 16 calendar months but less than or equal to 17 calendar months from the previous review.	The Responsible Entity had cyber security policies specified in the requirement that were reviewed and approved by the CIP Senior Manager or delegate, however the cyber security policies but did not include one of the elements in Parts 5.1 or 5.2; OR The Responsible Entity had cyber security policies specified in the requirement that were reviewed and approved by the CIP Senior Manager or delegate, however the approval was more than 17 calendar months but less than or equal to 18 calendar months from the previous review.	The Responsible Entity had cyber security policies specified in the requirement that were reviewed and approved by the CIP Senior Manager or delegate, however the cyber security policies but did not include either of the elements in Parts 5.1 or 5.2; OR The Responsible Entity did not have cyber security policies that were reviewed and approved by the CIP Senior Manager or delegate as specified in the requirement.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

Version History

Version	Date	Action	Change Tracking
1	TBD	Respond to FERC Order No. 829	NA

Standard Attachments

None

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 adoption, the text from the rationale text boxes was moved to this section.

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Implementation Plan

Project 2016-03 Cyber Security Supply Chain Risk Management
Reliability Standard CIP-013-1

Applicable Standard(s)

CIP-013-1 — Cyber Security — Supply Chain Risk Management

Requested Retirement(s)

None

Prerequisite Standard(s)

None

Applicable Entities

CIP-013-1 — Cyber Security — Supply Chain Risk Management

- Balancing Authority
- Distribution Provider that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
  - Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
  - Is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
  - Performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
  - Each Remedial Action Scheme (RAS) where the RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.
  - Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
- Generator Operator
- Generator Owner
- Reliability Coordinator
- Transmission Operator
- Transmission Owner

Background

On July 21, 2016, the Federal Energy Regulatory Commission (FERC) issued Order No. 829 directing NERC to develop a new or modified Reliability Standard that addresses supply chain risk management for industrial control system hardware, software, and computing and networking services associated with Bulk Electric System (BES) operations. Order No. 829 (at P 2) states:

> "[The Commission directs] NERC to develop a forward-looking, objective-based Reliability Standard to require each affected entity to develop and implement a plan that includes security controls for supply chain management for industrial control system hardware, software, and services associated with bulk electric system operations. The new or modified Reliability Standard should address the following security objectives, [discussed in detail in the Order]: (1) software integrity and authenticity; (2) vendor remote access; (3) information system planning; and (4) vendor risk management and procurement controls."

FERC directed NERC to submit the new or modified Reliability Standard within one year of the effective date of Order No. 829, i.e., by September 27, 2017.

General Considerations

Consistent with the directive to develop a forward-looking Reliability Standard, the implementation of CIP-013-1 does not require the abrogation or re-negotiation of contracts with vendors, suppliers or other entities executed as of the effective date of CIP-013-1 (See FERC Order No. 829, P. 36).

Effective Date

CIP-013-1 — Cyber Security — Supply Chain Risk Management
Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

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.

Initial Performance of Periodic Requirements

Requirement R2
The initial review and update, as necessary, of cyber security risk management plans specified in Requirement R2 must be completed within fifteen (15) calendar months of the effective date of CIP-013-1.

Definition

None

Retirement Date

None

Violation Risk Factor and Violation Severity Level Justifications

Project 2016-03 — Cyber Security — Supply Chain Risk Management

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in **Project 2016-03 — Cyber Security — Supply Chain Risk Management.** 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 by the ERO Sanctions Guidelines. The Emergency Operations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

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. A planning requirement that is administrative in nature.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
FERC seeks to ensure that VRFs 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
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs 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 VRF 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

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 CIP-013-01, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	R1 is a requirement in an Operations Planning time frame to develop one or more documented supply chain cyber security risk management plan(s). If violated, it 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 the requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report**

VRF Justifications for CIP-013-01, R1	
Proposed VRF	Medium
	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 has no sub-requirements and is assigned a single VRF.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This is a new requirement addressing specific reliability goals.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** A VRF of Medium is consistent with the NERC VRF definition as discussed above.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective, which is to develop one or more documented supply chain cyber security risk management plan(s). Since the requirement has only one objective, only one VRF was assigned.

VSLs for CIP-013-1, R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Responsible Entity implemented one or more documented supply chain risk management plan(s), but the plan(s) did not include one of the elements specified in Parts 1.1 or 1.2.	The Responsible Entity implemented one or more documented supply chain risk management plan(s), but the plan(s) did not include either of the elements specified in Parts 1.1 or 1.2.; OR The Responsible Entity did not implement one or more documented supply chain risk management plan(s) as specified in the Requirement.

VRF Justifications for CIP-013-1, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
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 for R1 is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, 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	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF Justifications for CIP-013-1, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology. The VSL is assigned for a single instance of failing to develop one or more documented supply chain cyber security risk management plan(s) that set forth the controls.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	An entity's violation of a single part of the plan specified in the requirement does not constitute a lapse in protection that compromises network security. Therefore a binary VSL is not warranted.
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	There is no documentation and implementation interdependence within the requirement.

VRF Justifications for CIP-013-1, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	R2 is a requirement in Operations Planning time frame that requires entities to implement its supply chain cybersecurity risk management plan(s) specified in Requirement R1. 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 the requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
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 has no sub-requirements and is assigned a single VRF.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This is a new requirement addressing specific reliability goals.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** A VRF of Medium is consistent with the NERC VRF definition as discussed above.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective and only one VRF was assigned. The requirement does not comingle more than one obligation.

VSLs for CIP-013-1, R2			
Lower	**Moderate**	**High**	**Severe**
The Responsible Entity reviewed and updated, as necessary, its supply chain cyber security risk management plan(s) and	The Responsible Entity reviewed and updated, as necessary, its supply chain cyber security risk management plan(s) and	The Responsible Entity reviewed and updated, as necessary, its supply chain cyber security risk management plan(s) and	The Responsible Entity did not review and update, as necessary, its supply chain cyber security risk management

obtained CIP Senior Manager or delegate approval but did so more than 15 calendar months but less than or equal to 16 calendar months since the previous review as specified in the Requirement.	obtained CIP Senior Manager or delegate approval but did so more than 16 calendar months but less than or equal to 17 calendar months since the previous review as specified in the Requirement.	obtained CIP Senior Manager or delegate approval but did so more than 17 calendar months but less than or equal to 18 calendar months since the previous review as specified in the Requirement.	plan(s) and obtain CIP Senior Manager or delegate approval within 18 calendar months of the previous review as specified in the Requirement.

VSL Justifications for CIP-013-1, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
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 for R2 is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, 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	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for CIP-013-1, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	An entity's violation of a single part of the requirement does not constitute a lapse in protection that compromises network security. Therefore a binary VSL is not warranted.
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	There is no documentation and implementation interdependence within the requirement.

VRF Justifications for CIP-013-1, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	R3 is a requirement in Operations Planning time frame that requires the Responsible Entity to implement one or more documented process(es) for software integrity and authenticity controls to address risks from compromised software and firmware on high and medium impact BES Cyber Systems. If violated, it 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 the requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
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 has no sub-requirements and is assigned a single VRF.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This is a new requirement addressing specific reliability goals.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** A VRF of Medium is consistent with the NERC VRF definition as discussed above.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R3 contains only one objective and only one VRF was assigned. The requirement does not comingle more than one obligation.

VSLs for CIP-013-1, R3			
Lower	Moderate	High	Severe
N/A	N/A	N/A	The Responsible Entity did not implement one or more documented process(es) for verifying the integrity and authenticity of software and firmware before being placed in operation on high and medium impact BES Cyber Systems as specified in the Requirement.

VSL Justifications for CIP-013-1, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
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 for R4 is Severe which is consistent with binary criteria. Guideline 2b: The proposed VSL does not use ambiguous terms, 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	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for CIP-013-1, R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Only a Severe VSL is assigned.
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	There is no documentation and implementation interdependence within the requirement.

VRF Justifications for CIP-013-01, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	R4 is a requirement in an Operations Planning time frame to implement one or more documented process(es) for controlling vendor remote access to high and medium impact BES Cyber Systems. If violated, it 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 the requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
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 has no sub-requirements and is assigned a single VRF.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This is a new requirement addressing specific reliability goals.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** A VRF of Medium is consistent with the NERC VRF definition as discussed above.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R4 contains only one objective and only one VRF was assigned. The requirement does not comingle more than one obligation.

VSLs for CIP-013-1, R4			
Lower	**Moderate**	**High**	**Severe**
N/A	The Responsible Entity implemented one or more documented process(es) for controlling vendor remote access to high and medium impact BES Cyber Systems, but did not include one of the elements specified in Part 4.1 through Part 4.3.	The Responsible Entity implemented one or more documented process(es) for controlling vendor remote access to high and medium impact BES Cyber Systems, but did not include two of the elements specified in Part 4.1 through Part 4.3.	The Responsible Entity implemented one or more documented process(es) for controlling vendor remote access to high and medium impact BES Cyber Systems, but did not include any of the elements specified in Part 4.1 through Part 4.3; OR The Responsible Entity did not implement one or more documented process(es) for controlling vendor remote access to high and medium impact BES Cyber Systems as specified in the Requirement.

VSL Justifications for CIP-013-1, R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R4 is not binary. Guideline 2b: The proposed VSLs do not use ambiguous terms, 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	The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for CIP-013-1, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	An entity's violation of a single part of the requirement does not constitute a lapse in protection that compromises network security. Therefore a binary VSL is not warranted.
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	There is no documentation and implementation interdependence within the requirement.

VRF Justifications for CIP-013-1, R5	
Proposed VRF	**Lower**
NERC VRF Discussion	R5 is a requirement in Operations Planning time frame that requires the Responsible Entity with at least one asset identified in CIP-002 containing low impact BES Cyber Systems to have one or more documented cyber security policies to address software integrity and authenticity and vendor remote access for its low impact BES Cyber Systems. If violated, it would not, under the emergency, abnormal, or restorative conditions anticipated by the policies, 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 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 has no sub-requirements and is assigned a single VRF.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This is a new requirement addressing specific reliability goals.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** A VRF of Lower is consistent with the NERC VRF definition as discussed above.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R5 contains only one objective and only one VRF was assigned. The requirement does not comingle more than one obligation

VSLs for CIP-013-1, R5			
Lower	**Moderate**	**High**	**Severe**
The Responsible Entity had cyber security policies specified in the requirement that were reviewed and approved by the CIP Senior Manager or delegate, however the approval was more than 15 calendar months but less than or equal to 16 calendar months from the previous review.	The Responsible Entity had cyber security policies specified in the requirement that were reviewed and approved by the CIP Senior Manager or delegate, however the approval was more than 16 calendar months but less than or equal to 17 calendar months from the previous review.	The Responsible Entity had cyber security policies specified in the requirement that were reviewed and approved by the CIP Senior Manager or delegate, however the cyber security policies but did not include one of the elements in Parts 5.1 or 5.2; OR The Responsible Entity had cyber security policies specified in the requirement that were reviewed and approved by the CIP Senior Manager or delegate, however the approval was more than 17 calendar months but less than or equal to 18 calendar months from the previous review.	The Responsible Entity had cyber security policies specified in the requirement that were reviewed and approved by the CIP Senior Manager or delegate, however the cyber security policies but did not include either of the elements in Parts 5.1 or 5.2; OR The Responsible Entity had cyber security policies specified in the requirement that were reviewed and approved by the CIP Senior Manager or delegate, however the approval was more than 15 calendar months but less than or equal to 16 calendar months from the previous review.

VSL Justifications for CIP-013-1, R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
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 for R5 is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, 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	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for CIP-013-1, R5	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	An entity's violation of a single part of the requirement does not constitute a lapse in protection that compromises network security. Therefore a binary VSL is not warranted.
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	There is no documentation and implementation interdependence within the requirement.

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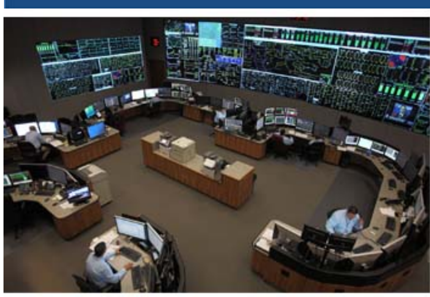
Technical Guidance and Examples

DRAFT CIP-013-1 – Cyber Security - Supply Chain Risk Management

January 17, 2017

RELIABILITY | ACCOUNTABILITY

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Introduction

Background

On July 21, 2016, the Federal Energy Regulatory Commission (FERC) issued Order No. 829 directing the North American Electric Reliability Corporation (NERC) to develop a new or modified Reliability Standard that addresses supply chain risk management for industrial control system hardware, software, and computing and networking services associated with Bulk Electric System (BES) operations as follows:

> *[The Commission directs] NERC to develop a forward-looking, objective-based Reliability Standard to require each affected entity to develop and implement a plan that includes security controls for supply chain management for industrial control system hardware, software, and services associated with bulk electric system operations. The new or modified Reliability Standard should address the following security objectives, [discussed in detail in the Order]: (1) software integrity and authenticity; (2) vendor remote access; (3) information system planning; and (4) vendor risk management and procurement controls.*

The Commission established a filing deadline of one year from the effective date of Order No. 829, which is September 27, 2017.

The Commission also explains that it "does not require NERC to impose any specific controls nor does the Commission require NERC to propose 'one-size-fits-all' requirements." (P 13)

> *Responsible entities should be required to achieve these four objectives but have the flexibility as to how to reach the objective (i.e., the Reliability Standard should set goals (the "what"), while allowing flexibility in how a responsible entity subject to the Reliability Standard achieves that goal (the "how"))*

Furthermore, FERC clarified the scope of the directives in Order No. 829 by stating (P 21):

> *we reiterate the statement in the NOPR that any action taken by NERC in response to the Commission's directive to address the supply chain-related reliability gap should respect "section 215 jurisdiction by only addressing the obligations of responsible entities" and "not directly impose obligations on suppliers, vendors or other entities that provide products or services to responsible entities."*

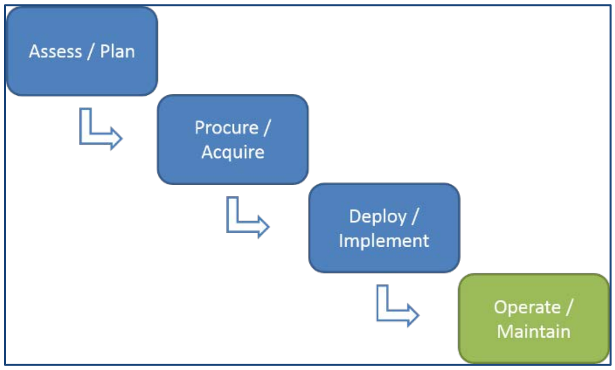
This technical reference provides a summary of the CIP-013-1 framework, which includes a description of the requirements that meet FERC's directives, including each of the objectives; the risk each objective is intended to address; some considerations for implementing the requirements; and examples of controls that responsible entities could use to meet the requirements.

CIP-013-1 Framework

Consistent with the Commission's directives, CIP-013-1 requires that responsible entities address each of the objectives set forth in Order No. 829 by developing and implementing a cyber security risk management plan and documented operating processes to protect against supply chain risks. The proposed standard is forward looking in that it does not require entities to renegotiate currently effective contracts in order to implement their plan.

Collectively, the provisions of Requirement R1 and R2 address an entity's controls for managing cyber security risks to BES Cyber Systems during the planning, acquisition, and deployment phases of the system life cycle, as shown below.

Notional BES Cyber System Life Cycle



Requirements R3 through R5 address controls for software integrity and authenticity and vendor remote access that apply to the operate/maintain phase of the system life cycle. The term *vendors* as used in the standard includes (i) developers or manufacturers of information systems, system components, or information system services; (ii) product resellers; or (iii) system integrators.

Responsible Entities

Proposed CIP-013-1 uses the same applicability as found in other CIP cyber security standards.

Requirement R1

R1. *Each Responsible Entity shall implement one or more documented supply chain risk management plan(s) that address controls for mitigating cyber security risks to BES Cyber Systems and, if applicable, associated Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets. The plan(s) shall address:*

1.1. *The use of controls in BES Cyber System planning and development to:*

1.1.1. *Identify and assess risk(s) during the procurement and deployment of vendor products and services; and*

1.1.2. *Evaluate methods to address identified risk(s).*

1.2. *The use of controls in procuring vendor product(s) or service(s) that address the following items, to the extent each item applies to the Responsible Entity's BES Cyber Systems and, if applicable, associated Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets:*

1.2.1. *Process(es) for notification of vendor security events;*

1.2.2. *Process(es) for notification when vendor employee remote or onsite access should no longer be granted;*

1.2.3. *Process(es) for disclosure of known vulnerabilities;*

1.2.4. *Coordination of response to vendor-related cyber security incidents;*

1.2.5. *Process(es) for verifying software integrity and authenticity of all software and patches that are intended for use;*

1.2.6. *Coordination of remote access controls for (i) vendor-initiated Interactive Remote Access and (ii) system-to-system remote access with a vendor(s); and*

1.2.7. *Other process(es) to address risk(s) as determined in Part 1.1.2, if applicable.*

The proposed Requirement addresses Order No. 829 directives for entities to implement a plan(s) that includes controls for mitigating cyber security risks in the supply chain. The plan(s) is required to address the following four objectives (P 45):

(1) Software integrity and authenticity;
(2) Vendor remote access;
(3) Information system planning; and
(4) Vendor risk management and procurement controls.

The cyber security risk management plan(s) specified in Requirement R1 apply to BES Cyber Systems and, to the extent applicable, associated Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets. These cyber systems cover the scope of assets needed to address FERC Order No. 829 directives, which specified that the standards must address supply chain risks to “industrial control system hardware, software, and computing and networking services associated with bulk electric system operations” (P 43).

Implementation of the cyber security risk management plan(s) does not require the Responsible Entity to renegotiate or abrogate existing contracts, consistent with Order No. 829 (P 36) as specified in the Implementation Plan.

To achieve the flexibility needed for supply chain cyber security risk management, responsible entities could use a "risk-based approach" to addressing the objectives. One example of a risk-based cyber security risk management plan is system-based, which describes specific controls for high, medium, and low impact BES Cyber Systems. Another example of a risk-based approach is vendor-based, allowing entities to develop its plan(s) around risk posed by various vendors of its BES Cyber Systems. This flexibility is important to account for the varying "needs and characteristics of responsible entities and the diversity of BES Cyber System environments, technologies, and risk (P 44)."

Objective: Information System Planning and Procurement

Requirement R1 Part 1.1 addresses Order No. 829 directives for identification and documentation of risks in the planning and development processes related to proposed BES Cyber Systems (P 56). The objective is to ensure entities consider risks and options for mitigating these risks when planning, acquiring, and deploying BES Cyber Systems.

Requirement R1 Part 1.2 addresses Order No. 829 directives for procurement controls to address vendor-related security concepts in future contracts for BES Cyber Systems and, if applicable, associated Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets (P 59). The objective of Part 1.2 is for entities to include these topics in their plans so that procurement and contract negotiation processes address the applicable risks. Implementation of elements contained in the entity's plan related to Part 1.2 is accomplished through the entity's procurement and contract negotiation processes. For example, entities can implement the plan by including applicable procurement items from their plan in Requests for Proposals (RFPs) and in negotiations with vendors. Obtaining specific controls in the negotiated contract may not be feasible and is not considered failure to implement an entity's plan.

Security Risks in Information System Planning and Procurement

The objective addresses risks identified in Order No. 829 (P 57):

> *The risk that responsible entities could unintentionally plan to procure and install unsecure equipment or software within their information systems, or could unintentionally fail to anticipate security issues that may arise due to their network architecture or during technology and vendor transitions.*

FERC also cited to the BlackEnergy malware campaign that used a zero day vulnerability (previously unknown) to remotely execute malicious code on devices that contain this vulnerability. Steps to "(1) minimize network exposure for all control system devices/subsystems; (2) ensure that devices were not accessible from the internet; (3) place devices behind firewalls; and (4) utilize secure remote access techniques" during system development and planning could mitigate such risk (P 57).

The objective also addresses additional risks identified in Order No. 829 (P 60):

> *the risk that responsible entities could enter into contracts with vendors who pose significant risks to their information systems, as well as the risk that products procured by a responsible entity fail to meet minimum security criteria. In addition, this objective addresses the risk that a compromised vendor would not provide adequate notice and related incident response to responsible entities with whom the vendor is connected.*

Entity Considerations in Meeting the Objective

In implementing Requirement R1, the responsible entity should consider the following:

- Cyber security risk(s) to the BES that could be introduced by a vendor in new or planned modifications to BES Cyber Systems.
- Vendor security processes and related procedures, including: system architecture, change control processes, remote access requirements, and security notification processes reviewed and evaluated during the planning, bidding, evaluation and contracting phases of the procurement process.
- Using periodic review processes with critical vendor(s) to review and assess any changes in vendor's security controls, product lifecycle management, supply chain, and roadmap to identify opportunities for continuous improvement.
- Vendor or service provider use of third party (e.g., product/personnel certification processes) or independent review methods to verify product and/or service provider security practices.
- Using third parties to conduct security assessments and penetration testing for specific vendors or "cloud based" service providers.
- Vendor supply chain channels and plans to mitigate potential risks or disruptions.
- Known system vulnerabilities; known threat techniques, tactics, and procedures; and related mitigation measures that could be introduced by vendor's information systems, components, or information system services.
- Corporate governance and approval processes. Consider establishing additional controls based on risk.
- Methods to minimize network exposure, e.g., prevent internet accessibility, use of firewalls, and use of secure remote access techniques.
- Methods to limit and/or control remote access from vendors to Responsible Entity's BES Cyber Systems.
- Use of procurement controls to aid with vendor risk assessments and mitigation measures for cyber security during the procurement process.

In implementing procurement controls, especially contract terms, responsible entities should be careful not to limit their negotiating ability with vendors through their CIP-013-1 plans. An example of this would be a procurement control that requires specific contract terms. This may have unintended consequences such as significant and unexpected cost increases for the product or service or vendors walking away from contracts.

Responsible entities may use their entire procurement process (e.g. defined requirements, request for proposal, bid evaluation, external vendor assessment tools and data, third party certifications and audit reports, etc.) rather than just contract terms to help them meet the objective and give them flexibility to negotiate contracts with vendors to efficiently mitigate risks.

Obtaining the desired specific cyber security controls in the negotiated contract may not be feasible with each vendor. Baseline controls should be established with the knowledge that every negotiated contract will be different. Factors such as competition, sole source of supply, or supplier's progression will determine the negotiated outcomes of the contract. This variation in contract terms is anticipated and is not considered failure to implement an entity's plan. In the event the vendor is unwilling to engage in the negotiation process for cyber security controls, the entity may explore other sources of supply or mitigating controls to reduce the risk to the BES cyber systems.

Potential Information System Planning Controls

Responsible entities may use various control(s) to address the security risk for this objective. Below are some examples of controls:

1.1. *The use of controls in BES Cyber System planning and development to:*

1.1.1. *Identify and assess risk(s) during the procurement and deployment of vendor products and services; and*

- Responsible Entity can develop plans to identify potential cyber security risks during the information system planning, system development, acquisition and deployment lifecycle processes. The plans can define the required security controls within the lifecycle that address threats, vulnerabilities, adverse impacts and risk to BES Cyber Systems.
- Participation of identified cross-organizational subject matter experts with appropriate representation of business operations, security architecture, information communications and technology, supply chain, compliance, and legal to be included in the planning and acquisition process.
- Identify potential risks based on information systems, system components, and/or information system services / integrators.
- Assess vendors based on their risk management controls. Examples of vendor risk management controls to consider include[1]:
  - Personnel background and screening practices by vendors
  - Training programs and assessments of personnel on cyber security
  - Formal security programs which include their technical, organizational, and security management practices
  - Vendor's physical and cyber security access controls to protect the facilities and product lifecycle
  - Review of vendor's security engineering principles in (i) developing layered protections; (ii) establishing sound security policy, architecture, and controls as the foundation for design; (iii) incorporating security requirements into the system development lifecycle; (iv) delineating physical and logical security boundaries; (v) ensuring that system developers are training on how to build security software; (vi) tailoring security controls to meet organizational and operational needs; (vii) performing threat modeling to identify use cases, threat agents, attack vectors, and attack patterns as well as compensating controls and design patterns needed to mitigate risk; and (viii) reducing risk to acceptable levels, thus enabling informed risk management decisions. (NIST SP 800-53 SA-8 – Security Engineering Principles)
  - System Development Life Cycle program (SDLC) methodology from design through patch management to understand how cyber security is incorporated throughout their processes
  - Review of certifications and their alignment with recognized industry and regulatory controls
  - Summary of any internal and independent cyber security testing performed on the products to ensure secure and reliable operations. Ask vendors to share third-party/independent product testing results during the request for proposal stage of acquisition process
  - Understand product roadmap to determine vendor support of software patches, firmware updates, replacement parts and ongoing maintenance support
  - Define any critical elements or components that may impact the operations or reliability of BES Cyber Systems

[1] Tools such as the Standardized Information Gathering (SIG) Questionnaire from the Shared Assessments Program can aid in assessing vendor risk.

- Identify processes and controls for ongoing management of Responsible Entity and vendor's intellectual property ownership and responsibilities, if applicable. This may include use of encryption algorithms for securing software code, data and information, designs, and proprietary processes while at rest or in transit.
- Identify any components of products that are not owned and managed by the vendor that may introduce additional risks, such as use of open source code or third party developers and manufacturers.

- Plan for information systems component end-of-life or discontinuation of product support. Define plans for replacement when support from the developer, vendor, or manufacturer is no longer provided. Provide justification and documented approval for the continued use of system components required to satisfy mission needs and ensure ongoing cyber security protection and reliability. (see NIST SP 800-53 SA-22 – Unsupported System Components)

1.1.2. *Evaluate methods to address identified risk(s).*

- Based on risk assessment, determine mitigating controls that can be applied in procurement and/or operation phase of product or service acquisition and implementation. Examples include:
  - Hardening the information systems and minimizing the attack surface vulnerabilities introduced with vendor products and services.
  - Ensure ongoing support and availability of system components for duration of expected life of products. Define the primary and alternate sources (if any) of components, parts and support services.
  - Controls to ensure system components, parts and support services are only acquired through trusted sources.
  - Identify alternative vendors that may supply critical elements and components, provide support services, or offer equivalent business functional solutions.
  - Review and address other risks in Requirement R1 Part 1.1.1.

Potential Procurement Controls

Responsible entities may use various control(s) to address the security risk for this objective. Below are examples of some controls:

1.2. *The use of controls in procuring vendor product(s) or service(s) that address the following items, to the extent each item applies to the Responsible Entity's BES Cyber Systems and, if applicable, associated Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets:*

- Responsible Entity can define cyber security terms in the procurement request for proposal (RFP) for BES Cyber Systems to ensure the vendor(s) understands the cyber security expectations and implements proper security controls throughout the design, development, testing, manufacturing, delivery, installation, support, and disposition of the product lifecycle. An example set of baseline supply chain cyber security procurement language for use by BES owners operators, and vendors during the procurement process can be obtained from the "Cybersecurity Procurement Language for Energy Delivery Systems" developed by the Energy Sector Control Systems Working Group (ESCSWG). Each Responsible Entity will need to determine the applicability of these sample terms and how such terms may complement other cyber security expectations in a clear and measurable manner.
- During negotiations of procurement contracts, the Responsible Entity can document the rationale, mitigating controls, or acceptance of deviations from the Responsible Entity's standard cyber security

procurement language that is applicable to the supplier's system component, system integrators, or external service providers.

1.2.1. *Process(es) for notification of vendor security events;*

- Request vendor cooperation to obtain Responsible Entity notification of any identified, threatened, attempted or successful breach of vendor's components, software or systems ("Security Event") that have potential adverse impacts to the availability or reliability of BES Cyber Systems.
- Security Event notifications to the Responsible Entity should be sent to designated point of contact as determined by the Responsible Entity and vendor. Notifications could include information on (i) mitigating controls that may be implemented by Responsible Entity, (ii) availability of patch or corrective components.
- Security Event notifications to the vendor should be sent to designated point of contact as determined by the vendor. Vendor should respond within a defined timeframe with information on (i) mitigating controls that may be implemented by Responsible Entity, (ii) availability of patch or corrective components.

1.2.2. *Process(es) for notification when vendor employee remote or onsite access should no longer be granted;*

- Using contract language, the Responsible Entity can maintain the right in its sole discretion to suspend or terminate remote or onsite access of vendor, or any individual employee of vendor, at any time without further notice for any reason. The vendor and Responsible Entity should define alternative methods that will be implemented in order to continue ongoing operations or services as needed.
- Request vendor cooperation in obtaining Responsible Entity notification of when vendor employee remote or onsite access should no longer be granted. This does not require the vendor to share sensitive information about vendor employees. Circumstances for no longer granting access to vendor employees include (i) vendor determines that any of the persons permitted access is no longer required, (ii) persons permitted access are no longer qualified to maintain access, or (iii) vendor's employment of any of the persons permitted access is terminated for any reason. Request vendor cooperation in obtaining Responsible Entity notification within a negotiated period of time of such determination.
- If vendor utilizes third parties to perform services to Responsible Entity, request vendor cooperation to obtain Responsible Entity's prior approval and third party adherence to the requirements and access termination rights imposed on the vendor directly.

1.2.3. *Process(es) for disclosure of known vulnerabilities;*

- Review vendor summary documentation of publicly disclosed vulnerabilities in the procured product and the status of the vendor's disposition of those publicly disclosed vulnerabilities.
- Request vendor cooperation in obtaining, within a negotiated time period after establishing appropriate confidentiality agreement, access to summary documentation of uncorrected security vulnerabilities in the procured product that have not been publicly disclosed. The summary documentation should include a description of each vulnerability and its potential impact, root cause, and recommended compensating security controls, mitigations, and/or procedural workarounds.
- After contract award and for duration of relationship with vendor, request vendor cooperation in obtaining access to summary documentation within a negotiated period of any identified security breaches involving the procured product or its supply chain. Documentation should include a summary

description of the breach, its potential security impact, its root cause, and recommended corrective actions involving the procured product.

1.2.4. *Coordination of response to vendor-related cyber security incidents;*

- Responsible Entity can agree on service level agreements for response to cyber security incidents and commitment from vendor to collaborate with Responsible Entity in implement mitigating controls and product corrections.
- In the event the Responsible Entity identifies a security incident that may or has resulted in an adverse impact to the availability or reliability of BES Cyber Systems, the Responsible Entity will seek vendor cooperation on notification processes, assistance and support requirements from the vendor.
- In the event the vendor identifies a vulnerability that has resulted in a cyber security incident related to the products or services provided to the Responsible Entity, vendor should provide notification to Responsible Entity per contract agreements. The vendor could provide defined information regarding the products or services at risk and appropriate precautions available to minimize risks.
- Until the cyber security incident has been corrected, the vendor could be requested to perform analysis of information available or obtainable, provide an action plan, provide ongoing status reports, mitigating controls, and final resolution within reasonable periods as agreed on by vendor and Responsible Entity.

1.2.5. *Process(es) for verifying software integrity and authenticity of all software and patches that are intended for use;*

- Request access to vendor documentation detailing the vendor patch management program and update process for all system components (including third-party hardware, software, and firmware). This documentation should include the vendor's method or recommendation for how the integrity of the patch is validated by Responsible Entity.
- Request access to vendor documentation for the procured products (including third-party hardware, software, firmware, and services) regarding the release schedule and availability of updates and patches that should be considered or applied. Documentation should include instructions for securely applying, validating and testing the updates and patches.
- For duration of the product life cycle, require vendor to provide appropriate software and firmware updates to remediate newly discovered vulnerabilities or weaknesses within a reasonable period. Consideration regarding service level agreements for updates and patches to remediate critical vulnerabilities should be a shorter period than other updates. If updates cannot be made available by the vendor within a reasonable period, the vendor should be required to provide mitigations and/or workarounds.
- Request vendors provide fingerprints or cipher hashes for all software so that the Responsible Entity can verify the values prior to installation on the BES Cyber System to verify the integrity of the software.
- Request vendors describe the processes they use for delivering software and the methods that can be used to verify the integrity and authenticity of the software upon receipt, including systems with preinstalled software.
- When third-party components are provided by the vendor, request vendors provide appropriate updates and patches to remediate newly discovered vulnerabilities or weaknesses.

1.2.6. *Coordination of remote access controls for (i) vendor-initiated Interactive Remote Access and (ii) system-to-system remote access with a vendor(s); and*

- Request vendors specify specific IP addresses, ports, and minimum privileges required to perform remote access services.
- Request vendors use individual user accounts that can be configured to limit access and permissions.
- Request vendors maintain their IT assets (hardware, software and firmware) connecting to Responsible Entity network with current updates to remediate security vulnerabilities or weaknesses identified by the original OEM or Responsible Entity.
- Request vendors document their processes for restricting connections from unauthorized personnel. Vendor personnel are not authorized to disclose or share account credentials, passwords or established connections.
- For vendor system-to-system connections that may limit the Responsible Entity's capability to authenticate the personnel connecting from the vendor's systems, request vendors maintain complete and accurate books, user logs, access credential data, records, and other information applicable to connection access activities for a negotiated time period.

1.2.7. *Other process(es) to address risk(s) as determined in Part 1.1.2, if applicable.*

- Request vendors provide Responsible Entity with audit rights that allow the Responsible Entity or designee to audit vendor's security controls, development and manufacturing controls, access to certifications and audit reports, and other relevant information.
- If vendor is not the original manufacturer of the products, require the vendor to certify that replacement parts supplied are made by the original equipment manufacturer and meet the applicable manufacturer data sheet or industry standard.
- For any replacement parts that vary from OEM specifications, request the vendor obtain prior approval by the Responsible Entity before substitution. Consider requiring vendor to provide testing certification or specifications that the replacement parts meet original product requirements.
- Require vendor to use designated or trusted providers for product delivery and services.
- Restrict the use and publication of Responsible Entity information in contracts, e.g., do not allow suppliers to publish your entity name, products or services on their websites or in sales materials.

Requirement R2

R2. *Each Responsible Entity shall review and update, as necessary, its supply chain cyber security risk management plan(s) specified in Requirement R1 at least once every 15 calendar months, which shall include:*

2.2. *Evaluation of revisions, if any, to address applicable new supply chain security risks and mitigation measures; and*

2.3. *Obtaining CIP Senior Manager or delegate approval.*

Objective: Review Supply Chain Cyber Security Risk Management Plans

The proposed requirement addresses Order No. 829 directives for entities to periodically reassess selected supply chain cyber security risk management controls (P. 46).

Order No. 829 also directs that the periodic assessment "ensure that the required plan remains up-to-date, addressing current and emerging supply chain-related concerns and vulnerabilities" (P. 47). Examples of sources of information that the entity considers include guidance or information issued by:

- NERC or the E-ISAC
- ICS-CERT
- Canadian Cyber Incident Response Centre (CCIRC)

Entity Considerations in Meeting the Objective

Requirement R2 allows responsible entities to incorporate the review of CIP-013-1 into their annual CIP-003 review. In the Requirement R2 review, responsible entities must consider new risks and available mitigation measures, which could come from a variety of sources that may include NERC, DHS, and other sources. The requirement also requires the identification of changes made, if any, to the controls based on this review.

CIP-003-6, Requirements R3 and R4 address the identification and delegation process for the CIP Senior Manager for this and the other CIP Standards.

Potential Supply Chain Cyber Security Risk Management Plan Controls

Responsible Entities may use various control(s) to address the security risk for this objective. Below are examples of potential controls:

2.1. *Evaluation of revisions, if any, to address applicable new supply chain security risks and mitigation measures; and*

- Responsible Entity will maintain a documented supply chain cyber security risk management plan
- Cross-organizational representative subject matter experts from appropriate business operations, security architecture, information communications and technology, supply chain, compliance, legal, etc. should collaboratively develop and be responsible to review the supply chain cyber security risk management plan at least once every 15 calendar months to reassess for any changes needed. Considerations for changes may include:
  - Requirements or guidelines from regulatory agencies
  - Industry best practices and guidance that improve cyber security risk management controls (e.g. NERC, DOE, DHS, ICS-CERT, Canadian Cyber Incident Response Center (CCIRC), NIST).

- Mitigating controls to address new and emerging supply chain-related cyber security concerns and vulnerabilities
- Internal organizational continuous improvement feedback regarding identified deficiencies, opportunities for improvement, and lessons learned. Examples may include changes to contract terms based on market maturity, capabilities, and cyber security advancements.

- Development of communications or training material to ensure any organizational areas affected by revisions to the supply chain cyber security risk management plan(s) are informed.

2.2. *Obtaining CIP Senior Manager or delegate approval.*

- The CIP Senior Manager, or approved delegate, reviews any changes to the supply chain cyber security risk management plan at least once every 15 calendar months. Reviews may be more frequent based on the timing and scope of changes to the supply chain cyber security risk management plan(s). Entities may incorporate the review into their annual CIP-003 review.
- Upon approval of changes to the supply chain cyber security risk management plan(s), the CIP Senior Manager or approved delegate should provide appropriate communications to the affected organizations or individuals.

Requirement R3

R3. *Each Responsible Entity shall implement one or more documented process(es) for verifying the integrity and authenticity of the following software and firmware before being placed in operation on high and medium impact BES Cyber Systems:*

3.1. *Operating System(s);*

3.2. *Firmware;*

3.3. *Commercially available or open-source application software; and*

3.4. *Patches, updates, and upgrades to 3.1 through 3.3.*

Objective: Software Integrity and Authenticity

The proposed requirement addresses Order No. 829 directives for verifying software integrity and authenticity prior to installation in BES Cyber Systems (P. 48). The objective of verifying software integrity and authenticity is to ensure that the software being installed in the BES Cyber System was not modified without the awareness of the software supplier and is not counterfeit.

Security Risks from Compromised Software

The Objective addresses the risk that an attacker could exploit legitimate vendor software delivery or patch management processes to deliver compromised software updates or patches to a BES Cyber System. [2] In Order No. 829, FERC provides additional context to this risk by stating that adequate authenticity and integrity controls could prevent malware campaigns or "Watering Hole" attacks that target the exploitation of vulnerable patch management processes.[3]

Entity Considerations in Meeting the Objective

In implementing Requirement R3, the responsible entity should consider their existing CIP cyber security policies and controls in addition to the following:

- Processes used by their vendors to deliver software and appropriate control(s) that will verify the integrity and authenticity of the software delivered through these processes. To the extent that the responsible entity utilizes automated systems such as a subscription service to download and distribute software including updates, consider how software integrity and authenticity can be verified through those processes.
- Integration of procurement controls from the responsible entity's supply chain cyber security risk management plan as identified in Requirement R1. During procurement of new systems, such as systems with preinstalled software, ask vendors to describe the processes they use for delivering software and the methods that can be used to verify the integrity and authenticity of the software upon receipt.
- Coordination of the responsible entity's integrity and authenticity control(s) with other cyber security policies and controls, including change management and patching processes, procurement controls, and incident response plans.
- Use of a secure central software repository after software authenticity and integrity have been validated, so that authenticity and integrity checks do not need to be performed before each installation.

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[2] *Id.* at P 48 and P 49. "This objective is intended to reduce the likelihood that an attacker could exploit legitimate vendor patch management processes to deliver compromised software updates or patches to a BES Cyber System" *(P 49).* FERC explains that the objective applies to all software (P 48).

[3] *Id.*

- Additional controls such as examples outlined in the Software, Firmware, and Information Integrity (SI-7) section of NIST Special Publication 800-53 Revision 4, or similar guidance.
- Additional controls such as those defined in FIPS-140-2, FIPS 180-4, or similar guidance, to ensure the cryptographic methods used are acceptable to the responsible entity.

Potential Software Integrity Controls

Responsible entities may use various control(s) to address the security risk for this objective. Below are examples of potential controls:

- Prior to installing software or placing software into operation on a BES Cyber System, verify that the software has been digitally signed and validate the signature to ensure that the software's integrity has not been compromised.
- Use public key infrastructure (PKI) with encryption to ensure that the software is not modified in transit by enabling only intended recipients to decrypt the software.
- Require vendors to provide fingerprints or cipher hashes for all software and verify the values prior to installation on a BES Cyber System to ensure the integrity of the software. Consider using a method for receiving the verification values that is different from the method used to receive the software from the vendor.
- Use trusted/controlled distribution and delivery options to reduce supply chain risk (e.g., requiring tamper-evident packaging of software during shipping.)

Potential Software Authenticity Controls

Responsible entities may use various control(s) to address the security risk for this objective. Below are examples of potential controls:

- Obtain software from an authenticated source before installation.
- Prior to installing software or placing software into operation on a BES Cyber System, verify that the software has been digitally signed and validate the signature to ensure that the software is authentic.
- Use public key infrastructure (PKI) with encryption to ensure that the software is authentic by enabling only intended recipients to decrypt the software.
- Use trusted/controlled distribution and delivery options to reduce supply chain risk (e.g., requiring tamper-evident packaging of software during shipping).

Requirement R4

R4. Each Responsible Entity shall implement one or more documented process(es) for controlling vendor remote access to high and medium impact BES Cyber Systems. The process(es) shall provide the following for (i) vendor-initiated Interactive Remote Access and (ii) system-to-system remote access with a vendor(s): *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Authorization of remote access by the Responsible Entity;

4.2. Logging and monitoring of remote access sessions to detect unauthorized activity; and

4.3. Disabling or otherwise responding to unauthorized activity during remote access sessions.

Objective: Vendor Remote Access to BES Cyber Systems

The proposed requirement addresses Order No. 829 directives for controls on vendor-initiated remote access to BES Cyber Systems covering both user-initiated and machine-to-machine vendor remote access (P. 51). The objective of the Requirement is to mitigate potential risks of a compromise at a vendor from traversing over an unmonitored remote access connection.

The objective of Requirement R4 Part 4.3 is for entities to have the ability to rapidly disable remote access sessions in the event of a system breach as specified in Order No. 829 (P 52).

Security Risk Related to Vendor Remote Access

The objective addresses risks identified in Order No. 829:

> *the threat that vendor credentials could be stolen and used to access a BES Cyber System without the responsible entity's knowledge, as well as the threat that a compromise at a trusted vendor could traverse over an unmonitored connection into a responsible entity's BES Cyber System.*[4]

Entity Considerations in Meeting the Objective

Requirement R4 Part 4.1 requires responsible entities to implement a control(s) to restrict vendor access, which includes access by a person or a machine. The control(s) used by a responsible entity may vary depending on entity-specific factors and existing cyber security policies (i.e. different entities grant varying levels and amounts of vendor remote access depending on entity needs.)

In addition to authorizing remote access, Requirement R4 requires the implementation of a control(s) to monitor vendor access (Part 4.2). Therefore, if a vendor is allowed to access BES Cyber Systems, then the responsible entity is required to monitor this access. This control(s) will address the Commission's concern that the responsible entity may not have the level of visibility over the remote access system-to-system session on the BES Cyber Systems, which could allow malicious intrusion attempts to take place.

Requirement R4 Part 4.3 addresses the detection of unauthorized (i.e., inappropriate) activity as well as the response to the detection of such activity, while allowing the responsible entity flexibility in the control(s) it uses to meet this part of the security objective.

It is important to recognize that these new requirements may be partially addressed by the responsible entity's existing remote access controls used to comply with approved CIP Standards. In implementing Requirement R4, the responsible entity should consider their existing CIP cyber security policies and controls.

[4] 156 FERC ¶ 61,050 at P 52.

For Requirement R4 Part 4.1, an entity may already have some authorization controls in place that will support meeting this objective.[5] If these controls do not fully cover vendor-initiated Interactive Remote Access and system-to-system remote access with a vendor(s), additional remote access controls are needed to meet the objective. For example, if an entity allows vendor remote access only during specific circumstances, such as response to system problems, the entity put other controls in place to disable vendor remote access at other times. Other entities may find that vendor remote access is required at all times and may use other controls as discussed below to achieve the objective. For example, the entity could employ operator-based controls that use various identification methods to control vendor remote access pathways into BES Cyber Systems.

For Requirement R4 Part 4.2, an entity may have monitoring controls in place for some BES Cyber Systems, however the controls may not necessarily address remote access session monitoring and alerting.[6] These existing monitoring controls could be enhanced to meet the objective. Entities should consider:

- Available capabilities and technologies for monitoring session activity with a vendor
- Setting up processes and parameters to monitor and log remote access login attempts to detect unauthorized remote access
- Development of procurement technical specifications for vendor remote access to support monitoring vendor remote access traffic during remote sessions

Entities may find it appropriate to modify their existing controls associated alert and response processes for Requirement R4 Part 4.3 including the threshold for alerting, persons alerted, as well as the timelines for alerting and responding. Entities may also find it appropriate to modify their existing controls and processes associated with CIP-008-5 - Cyber Incident Response Plan. Other considerations:

- Entity determination of appropriate response to unauthorized access from personnel, technology, and risk standpoints
- Thresholds for alerting, persons alerted, and the timelines for alerting and responding to unauthorized activity in order ensure reliable BES operations
- Availability and reliability of methods to prevent vendor remote access or disable vendor remote access sessions if unauthorized or illegitimate access is detected.

Potential Remote Access Controls

Responsible Entities may use various control(s) to address the security risk for this objective. Below are examples of potential controls:

<u>For Requirement R4 Part 4.1 (Authorization Controls):</u>

- Use an operator controlled, time limited (e.g., lock out, tag out) process for vendor remote access. Example approaches may include:
  - For user initiated sessions, use token authentication by authorized personnel. Token activation is for a specific timeframe or specific location. For machine-to-machine sessions, use encryption and multi-factor authentication that changes on a determined timeframe.

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[5] For example, CIP-004-6 - Personnel and Training, which covers training and personnel risk assessment requirements, and CIP-007-6 Requirement 5 – System Access Control, which covers account access controls.

[6] CIP-005-5 Requirement R1.5 covers detection of malicious communications for medium and high BES Cyber Systems in Control Centers, and CIP-007-6 Requirements 4.1 and 4.2 covers logging of access and detection of failed access attempts.

    - Designate specific timeframe access for the exchange of information. The responsible entity is responsible for ensuring access is terminated at the conclusion of the timeframe.
    - Terminate access upon notification the underlying purpose has ended.
    - Consider requiring vendors to specifically request remote access in order to support operator controlled and time limited access.

For Requirement R4 Part 4.2 (Logging and Monitoring Controls):

- Set up logging and monitoring parameters on key attributes and thresholds as appropriate, such as number of failed log-in attempts.
- Log and monitor vendor remote access sessions and review logs for abnormal behavior. Have a method for terminating suspicious sessions.
- Consider extended use of jump hosts for access to protected networks (e.g. specific jump hosts dedicated to vendor remote access).
- Use monitoring and control mechanisms and processes at the boundary between the responsible entity and vendors (e.g. application level firewalls or intrusion detection/prevention systems).
- Change default parameters for authentication mechanisms (e.g., passwords) or access/network protocols prior to installing Cyber Assets.

For Requirement R4 Part 4.3 (Disable Access and Entity Response Controls):

- Set up alerting parameters and thresholds on key attributes as appropriate for the entity (e.g., number of failed login attempts or detection of inappropriate activities).
- Set up alerting and response processes so that inappropriate vendor remote access sessions may be disabled or otherwise responded to in a timely manner.

Requirement R5

R5. *Each Responsible Entity with at least one asset identified in CIP-002 containing low impact BES Cyber Systems shall have one or more documented cyber security policies, which shall be reviewed and approved by the CIP Senior Manager or delegate at least once every 15 calendar months, that address the following topics for its low impact BES Cyber Systems:*

5.1. *Integrity and authenticity of software and firmware and any patches, updates, and upgrades to software and firmware; and*

5.2. *Controlling vendor-initiated remote access, including system-to-system remote access with vendor(s).*

Objective: Software and Vendor Remote Access Risk Mitigation in Low Impact BES Cyber Systems

The proposed requirement addresses Order No. 829 directives for (i) verifying software integrity and authenticity; and (ii) controlling vendor remote access, as they apply to low impact BES Cyber Systems. (P. 48 and P. 51).

Security Risks

Preceding sections discuss the related risks as identified in Order No. 829. Requirement R5 is intended to address these risks as they apply to low impact BES Cyber Systems. Responsible Entities have flexibility to use an approach for low impact BES Cyber Systems that is different from the approach used for medium and high impact BES Cyber Systems.

Entity Considerations for Meeting the Objective

In implementing Requirement R5, the responsible entity should consider the following:

- Considerations and controls for addressing software risks and vendor remote access risks to high and medium impact BES Cyber Systems discussed above that the entity determines are also applicable to its low impact BES Cyber Systems.
- Entity processes for addressing software risks and vendor remote access risks per Requirements R3 and R4. Consider whether to include low impact BES Cyber Systems in these processes, or alternatively develop a separate cyber security policy or process(es) to address low impact BES Cyber Systems.
- Existing CIP cyber security policies and controls that can be included or referenced in a cyber security policy to meet the objective. For example, some electronic access controls established by an entity for low impact BES Cyber Systems pursuant to approved CIP-003 requirements may be part of the cyber security policy specified in Requirement R5 for controlling vendor-initiated remote access, including system-to-system remote access with vendor(s).
- Asset management factors applicable to the entity. Entities can develop its cyber security policies either by individual asset or by groups of assets. As noted in the rationale section of proposed CIP-013-1, an inventory, list, or discrete identification of low impact BES Cyber Systems or their BES Cyber Assets is not required.

Potential Controls for Cyber Security Policies to Meet the Objective

Responsible entities may use various control(s) to address the security risks for this objective. Below are examples of potential controls that an entity could include in its cyber security policy or process(es):

- Policies, procedures, and/or checklists for personnel to check that software has been digitally signed and validate the signature to ensure that the software's integrity has not been compromised.
- Policies, procedures, and/or checklists that support obtaining software from trustworthy sources.
- Policies for using trusted/controlled distribution and delivery options to reduce supply chain risk (e.g., requiring tamper-evident packaging of software during shipping.)
- Policies, procedures, and/or checklists for applying other controls discussed above that address software risks and vendor remote access.

References

- Utilities Technology Council (UTC) "Cyber Supply Chain Risk management for Utilities – Roadmap for Implementation"
- ISO/IEC 27036 – Information Security in Supplier Relationships
- NIST SP 800-53 - Security and Privacy Controls for Federal Information Systems and Organizations System and Services Acquisition SA-3, SA-8 and SA-22
- NIST SP 800-161 - Supply Chain Risk Management Practices for Federal Information Systems and Organizations;
- Energy Sector Control Systems Working Group (ESCSWG) - "Cybersecurity Procurement Language for Energy Delivery Systems"

Order No. 829 Citation	Directive/Guidance	Resolution
P 43	[the Commission directs] that NERC, pursuant to section 215(d)(5) of the FPA, develop a forward-looking, objective-driven new or modified Reliability Standard to require each affected entity to develop and implement a plan that includes security controls for supply chain management for industrial control system hardware, software, and services associated with bulk electric system operations.	Proposed CIP-013-1 addresses the directive. The purpose of the proposed standard is: *To mitigate cyber security risks to the reliable operation of the Bulk Electric System (BES) by implementing security controls for supply chain risk management of BES Cyber Systems.*
P 44	[the Commission directs] NERC to submit the new or modified Reliability Standard within one year of the effective date of this Final Rule. NERC should submit an informational filing [by December 26, 2016] with a plan to address the Commission's directive.	The proposed standard must be filed by September 27, 2017. NERC filed its plan to address the directive on December 15, 2016.
P 45	The plan required by the new or modified Reliability Standard developed by NERC should address, at a minimum, the following four specific security objectives in the context of addressing supply chain management risks: (1) software integrity and authenticity; (2) vendor remote access; (3) information system planning; and (4) vendor risk management and procurement controls. Responsible entities should be required to achieve these four objectives but have the flexibility as to how to reach the objective (i.e., the Reliability Standard should set goals (the "what"), while allowing flexibility in how a responsible entity subject to the Reliability Standard achieves that goal (the "how")).	The directive is addressed by Requirements R1, R3, R4, and R5 of proposed CIP-013-1. Requirement R1 specifies that entities must implement one or more documented supply chain risk management plan(s) that address controls for mitigating cyber security risks to BES Cyber Systems and, if applicable, associated Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets. The plans address the four objectives from Order No. 829 (P 45) during the planning, acquisition, and deployment phases of the system life cycle Requirements R3 through R5 address controls for software integrity and authenticity and vendor remote access that apply to the operate/maintain phase of the system life cycle as described further below.

Order No. 829 Citation	Directive/Guidance	Resolution
		<u>Proposed CIP-013-1 Requirement R1</u> **R1.** Each Responsible Entity shall implement one or more documented supply chain risk management plan(s) that address controls for mitigating cyber security risks to BES Cyber Systems and, if applicable, associated Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets. The plan(s) shall address: **1.1.** The use of controls in BES Cyber System planning and development to: **1.1.1.** Identify and assess risk(s) during the procurement and deployment of vendor products and services; and **1.1.2.** Evaluate methods to address identified risk(s). **1.2.** The use of controls in procuring vendor product(s) or service(s) that address the following items, to the extent each item applies to the Responsible Entity's BES Cyber Systems and, if applicable, associated Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets: **1.2.1.** Process(es) for notification of vendor security events;

Order No. 829 Citation	Directive / Guidance	Resolution
		1.2.2. Process(es) for notification when vendor employee remote or onsite access should no longer be granted; **1.2.3.** Process(es) for disclosure of known vulnerabilities; **1.2.4.** Coordination of response to vendor-related cyber security incidents; **1.2.5.** Process(es) for verifying software integrity and authenticity of all software and patches that are intended for use; **1.2.6.** Coordination of remote access controls for (i) vendor-initiated Interactive Remote Access and (ii) system-to-system remote access with a vendor(s); and **1.2.7.** Other process(es) to address risk(s) as determined in Part 1.1.2, if applicable.
P 46	The new or modified Reliability Standard should also require a periodic reassessment of the utility's selected controls. Consistent with or similar to the requirement in Reliability Standard CIP-003-6, Requirement R1, the Reliability Standard should require the responsible entity's CIP Senior Manager to review and approve the controls adopted to meet the specific security objectives identified in the Reliability Standard at least every 15 months. This periodic assessment should better ensure that the required plan remains up-to-date, addressing current and emerging supply chain-related concerns and vulnerabilities.	The directive is addressed in proposed CIP-013-1 Requirement R2. **Proposed CIP-013-1 Requirement R2** **R2.** Each Responsible Entity shall review and update, as necessary, its supply chain cyber security risk management plan(s) specified in Requirement R1 at least once every 15 calendar months, which shall include: **2.1.** Evaluation of revisions, if any, to address applicable new supply chain security risks and mitigation measures; and

Order No. 829 Citation	Directive/Guidance	Resolution
		2.2. Obtaining CIP Senior Manager or delegate approval.
p 47	Also, consistent with this reliance on an objectives-based approach, and as part of this periodic review and approval, the responsible entity's CIP Senior Manager should consider any guidance issued by NERC, the U.S. Department of Homeland Security (DHS) or other relevant authorities for the planning, procurement, and operation of industrial control systems and supporting information systems equipment since the prior approval, and identify any changes made to address the recent guidance.	The directive is addressed in proposed CIP-013-1 Requirement R2 part 2.1 (shown above) and supporting guidance. **Proposed CIP-013-1 Rationale for Requirement R2:** Order No. 829 also directs that the periodic assessment "ensure that the required plan remains up-to-date, addressing current and emerging supply chain-related concerns and vulnerabilities" (P. 47). Examples of sources of information that the entity considers include guidance or information issued by: • NERC or the E-ISAC • ICS-CERT • Canadian Cyber Incident Response Centre (CCIRC) *Technical Guidance and Examples* document developed by the drafting team includes example controls.
Objective 1: Software Integrity and Authenticity		
P 48	The new or modified Reliability Standard must address verification of: (1) the identity of the software publisher for all software and patches that are intended for use on BES Cyber Systems; and (2) the integrity of the software and patches before they are installed in the BES Cyber System environment.	The directive is addressed in proposed CIP-013-1 Requirement R1 Part 1.2.5 (discussed above) and Requirements R3 and R5 Part 5.1. Requirement R3 applies to high and medium impact BES Cyber Systems. Requirement R5 applies to low impact BES Cyber Systems. **Proposed CIP-013-1 Requirement R3** **R3.** Each Responsible Entity shall implement one or more documented process(es) for verifying the integrity and authenticity of the following software and

Order No. 829 Citation	Directive/Guidance	Resolution
		firmware before being placed in operation on high and medium impact BES Cyber Systems: **3.1.** Operating System(s); **3.2.** Firmware; **3.3.** Commercially available or open-source application software; and **3.4.** Patches, updates, and upgrades to 3.1 through 3.3. **<u>Proposed CIP-013-1 Requirement R5</u>** **R5.** Each Responsible Entity with at least one asset identified in CIP-002 containing low impact BES Cyber Systems shall have one or more documented cyber security policies, which shall be reviewed and approved by the CIP Senior Manager or delegate at least once every 15 calendar months, that address the following topics for its low impact BES Cyber Systems: **5.1.** Integrity and authenticity of software and firmware and any patches, updates, and upgrades to software and firmware; and...
Objective 2: Vendor Remote Access to BES Cyber Systems		
P 51	The new or modified Reliability Standard must address responsible entities' logging and controlling all third-party (i.e., vendor) initiated remote access sessions. This objective covers both user-initiated and machine-to-machine vendor remote access.	The directive is addressed by proposed CIP-013-1 Requirement R4 Part 4.1 and 4.2 and Requirement R5 Part 5.2. Requirement R4 applies to high and medium impact BES Cyber Systems. Requirement R5 applies to low impact BES Cyber Systems.

Order No. 829 Citation	Directive / Guidance	Resolution
		<u>Proposed CIP-013-1 Requirement R4</u> **R4.** Each Responsible Entity shall implement one or more documented process(es) for controlling vendor remote access to high and medium impact BES Cyber Systems. The process(es) shall provide the following for (i) vendor-initiated Interactive Remote Access and (ii) system-to-system remote access with a vendor(s): **4.1.** Authorization of remote access by the Responsible Entity; **4.2.** Logging and monitoring of remote access sessions to detect unauthorized activity; and **4.3.** Disabling or otherwise responding to unauthorized activity during remote access sessions. **<u>Proposed CIP-013-1 Requirement R5</u>** **R5.** Each Responsible Entity with at least one asset identified in CIP-002 containing low impact BES Cyber Systems shall have one or more documented cyber security policies, which shall be reviewed and approved by the CIP Senior Manager or delegate at least once every 15 calendar months, that address the following topics for its low impact BES Cyber Systems: **5.2.** Controlling vendor-initiated remote access, including system-to-system remote access with vendor(s).

Order No. 829 Citation	Directive/Guidance	Resolution
P 52	In addition, controls adopted under this objective should give responsible entities the ability to rapidly disable remote access sessions in the event of a system breach.	The directive is addressed by Requirement R4 Part 4.3 (above) and Requirement R5 Part 5.2 (above).
Objective 3: Information System Planning and Procurement		
P 56	As part of this objective, the new or modified Reliability Standard must address a responsible entity's CIP Senior Manager's (or delegate's) identification and documentation of the risks of proposed information system planning and system development actions. This objective is intended to ensure adequate consideration of these risks, as well as the available options for hardening the responsible entity's information system and minimizing the attack surface.	The directive is addressed in proposed CIP-013-1 Requirement R1 Part 1.1 (shown above).
Objective 4: Vendor Risk Management and Procurement Controls		
P 59	The new or modified Reliability Standard must address the provision and verification of relevant security concepts in future contracts for industrial control system hardware, software, and computing and networking services associated with bulk electric system operations. Specifically, NERC must address controls for the following topics: (1) vendor security event notification processes; (2) vendor personnel termination notification for employees with access to remote and onsite systems; (3) product/services vulnerability disclosures, such as accounts that are able to bypass authentication or the presence of hardcoded passwords; (4) coordinated incident response activities; and (5) other related aspects of procurement. NERC should also consider provisions to help responsible entities obtain necessary information from their vendors to minimize potential disruptions from vendor-related security events.	The directive is addressed in proposed CIP-013-1 Requirement R1 Part 1.2 (shown above).

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

On January 21, 2016, the Federal Energy Regulatory Commission (Commission) issued Order No. 822, approving seven Critical Infrastructure Protection (CIP) Reliability Standards and new or modified definitions to be incorporated into the Glossary of Terms Used in NERC Reliability Standards. In addition to approving the seven CIP Reliability Standards, the Commission, directed NERC to, among other things,: (1) "…develop modifications to the CIP Reliability Standards to provide mandatory protection for transient devices used at Low Impact BES Cyber Systems…", and (2) modify the definition of LERC.

In response to these directives, NERC first modified Reliability Standard CIP-003-6 to address the LERC directive~~,~~ which has a regulatory deadline of March 31, 2017 for filing with the Commission. The revisions associated with the LERC directive were developed and posted for comment and ballot in July 2016 in draft Reliability Standard CIP-003-7. The revisions were not approved by stakeholders and based on the feedback received, the drafting team revised its approach and posted the revisions for an additional comment period and ballot. CIP-003-7 passed the additional ballot that ended on December 5, 2016.

For the transient device directive, NERC initially posted draft revisions for an informal comment period from November 1-18, 2016. This draft of Reliability Standard CIP-003-7(i) incorporates the proposed TCA language, as modified based on stakeholder comment, with the recently passed LERC revisions. The intent of this approach is to allow entities time to efficiently plan and implement the required modifications for low impact BES Cyber Systems. The Standard Drafting Team (SDT) approach to address the transient device directive is summarized below.

The SDT revised Attachment 1 of CIP-003-7 to include requirements that mitigate the risk to the BES of malware propagation from transient devices to low impact BES Cyber Systems. Attachment 1 contains and outlines the required sections of a Responsible Entity's cyber security plan(s) for its low impact BES Cyber Systems per Requirement R2. Previously, cyber security plan(s) were required to address four subject matter areas: (1) cyber security awareness; (2) physical security controls; (3) electronic access controls; and (4) Cyber Security Incident response. In keeping with the stakeholder approved approach to incorporate into one standard all the requirements applicable to assets containing low impact BES Cyber Systems, the SDT expanded CIP-003-7 Attachment 1 to include a fifth area: "Transient Cyber Asset and Removable Media Malicious Code Risk Mitigation." Requiring the Responsible Entity to develop and implement these plans will provide higher assurance against the propagation of malware from transient devices.

In addition, the SDT determined it was necessary to revise the definitions of a Transient Cyber Asset (TCA) and Removable Media to ensure applicability of security controls and provide additional clarity. As well, the revised definitions accommodate use of the terms for all impact levels: high, medium, and low. This is important for those entities that may opt to deploy one program to manage TCAs and Removable Media across multiple impact level assets.

The proposed revised definition of a Transient Cyber Asset (TCA) is:

A Cyber Asset that is:

1. *capable of transmitting or transferring executable code,*
2. *not included in a BES Cyber System,*
3. *not a Protected Cyber Asset (PCA) associated with high or medium impact BES Cyber Systems, and*
4. *directly connected (e.g., using Ethernet, serial, Universal Serial Bus, or wireless including near field or Bluetooth communication) for 30 consecutive calendar days or less to a:*
   - *BES Cyber Asset,*
   - *network within an Electronic Security Perimeter (ESP) containing high or medium impact BES Cyber Systems, or*
   - *PCA associated with high or medium impact BES Cyber Systems.*

Examples of Transient Cyber Assets include, but are not limited to, Cyber Assets used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.

The proposed revised definition of Removable Media is:

Storage media that:

1. *are not Cyber Assets,*
2. *are capable of transferring executable code,*
3. *can be used to store, copy, move, or access data, and*
4. *are directly connected for 30 consecutive calendar days or less to a:*
   - *BES Cyber Asset,*
   - *network within an Electronic Service Perimeter (ESP) containing high or medium impact BES Cyber Systems, or*
   - *Protected Cyber Asset associated with high or medium impact BES Cyber Systems.*

Examples of Removable Media include, but are not limited to, floppy disks, compact disks, USB flash drives, external hard drives, and other flash memory cards/drives that contain nonvolatile memory.

As proposed, Section 5 of Attachment 1 of CIP-003-7(i) mandates that entities have malware protection on TCAs (both entity and vendor-managed) and for Removable Media. The SDT proposes that it is necessary to distinguish between the specific protections for: (i) TCAs managed by the Responsible Entity, (ii) TCAs managed by a party other than the Responsible Entity (e.g. vendors or contractors), and (iii) Removable Media.

For TCAs managed by the Responsible Entity, Section 5 requires the Responsible Entity to use one or a combination of the following to mitigate the introduction of malicious code: antivirus software, application whitelisting, or some other method. The SDT recognizes that entities manage these devices in two fundamentally different ways. Some entities maintain a preauthorized inventory of transient devices (i.e., manage in an ongoing manner) while others have a checklist for transient devices prior to connecting them to a BES Cyber System (i.e., manage in an on-demand manner). The SDT acknowledges that both methods are effective and Section 5 permits either form of management. Because of the higher frequency in which these entity-managed devices are used, the controls required for these devices are more specific.

For Transient Cyber Assets managed by a party other than the Responsible Entity, Section 5 requires the Responsible Entity to review and verify the malware mitigation mechanism(s) used by the third party prior to connecting the Transient Cyber Asset (per Transient Cyber Asset capability).

For Removable Media, Section 5 requires entities to employ methods to detect malicious code and mitigate the threat of detected malicious code prior to connecting to a low impact BES Cyber System.

In summary, the SDT made the following changes to address the directive:

1. Revised the definitions of Transient Cyber Asset (TCA) and Removable Media.
2. Revised Requirement R1, by adding Parts 1.2.5 and 1.2.6 to include the complementary policies for the Transient Cyber Assets and Removable Media Malicious Code Risk Mitigation in Requirement R2 (Attachment 1 of CIP-003-7(i)).
3. Revised the requirement language (Requirement R2) in Attachment 1 of CIP-003-7 by adding Section 5 - Transient Cyber Assets and Removable Media Malicious Code Risk Mitigation.
4. Revised the associated VSLs for Requirements R1 and R2 of CIP-003-7.
5. Revised the evidential language of Attachment 2 of CIP-003-7 by adding Section 5 - Transient Cyber Assets and Removable Media Malicious Code Risk Mitigation to complement the revised requirement language.

Completed Actions	Date
Standard Authorization Request approved	July 20, 2016
Draft 1 of CIP-003-7(i) posted for formal comment and initial ballot	December 9, 2016 – January 23, 2017

Anticipated Actions	Date
10-day final ballot	~~February~~January, 2017
NERC Board of Trustees adoption	February, 2017
Petition filed with FERC	March, 2017

A. Introduction

1. **Title:** Cyber Security — Security Management Controls
2. **Number:** CIP-003-7(i)
3. **Purpose:** To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the Bulk Electric System (BES).
4. **Applicability:**

4.1. Functional Entities: For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

4.1.1. Balancing Authority

4.1.2. Distribution Provider that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:

4.1.2.1. Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:

4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.1.2.2. Each Special Protection System (SPS) or Remedial Action Scheme (RAS) where the SPS or RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.1.3. Generator Operator

4.1.4. Generator Owner

4.1.5. Interchange Coordinator or Interchange Authority

4.1.6. Reliability Coordinator

4.1.7. Transmission Operator

4.1.8. Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in Section 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each SPS or RAS where the SPS or RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-003-7(i):

4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters (ESPs).

4.2.3.3. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. Effective Dates:

See Implementation Plan for CIP-003-7(i).

6. Background:

Standard CIP-003 exists as part of a suite of CIP Standards related to cyber security, which require the initial identification and categorization of BES Cyber Systems and require organizational, operational, and procedural controls to mitigate risk to BES Cyber Systems.

The term policy refers to one or a collection of written documents that are used to communicate the Responsible Entities' management goals, objectives and expectations for how the Responsible Entity will protect its BES Cyber Systems. The use of policies also establishes an overall governance foundation for creating a culture of security and compliance with laws, regulations, and standards.

The term documented processes refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in its documented processes, but it must address the applicable requirements.

The terms program and plan are sometimes used in place of documented processes where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as plans (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term program may refer to the organization's overall implementation of its policies, plans, and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Reliability Standards could also be referred to as a program. However, the terms program and plan do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high, medium, and low impact BES Cyber Systems. For example, a single cyber security awareness program could meet the requirements across multiple BES Cyber Systems.

Measures provide examples of evidence to show documentation and implementation of the requirement. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an "or," and numbered items are items that are linked with an "and."

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the BES. A review of UFLS tolerances defined within Regional Reliability Standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

B. Requirements and Measures

R1. Each Responsible Entity shall review and obtain CIP Senior Manager approval at least once every 15 calendar months for one or more documented cyber security policies that collectively address the following topics: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1. For its high impact and medium impact BES Cyber Systems, if any:

1.1.1. Personnel and training (CIP-004);

1.1.2. Electronic Security Perimeters (CIP-005) including Interactive Remote Access;

1.1.3. Physical security of BES Cyber Systems (CIP-006);

1.1.4. System security management (CIP-007);

1.1.5. Incident reporting and response planning (CIP-008);

1.1.6. Recovery plans for BES Cyber Systems (CIP-009);

1.1.7. Configuration change management and vulnerability assessments (CIP-010);

1.1.8. Information protection (CIP-011); and

1.1.9. Declaring and responding to CIP Exceptional Circumstances.

1.2. For its assets identified in CIP-002 containing low impact BES Cyber Systems, if any:

1.2.1. Cyber security awareness;

1.2.2. Physical security controls;

1.2.3. Electronic access controls;

1.2.4. Cyber Security Incident response;

1.2.5. Transient Cyber Assets and Removable Media Malicious Code Risk Mitigation; and

1.2.6. Declaring and responding to CIP Exceptional Circumstances.

M1. Examples of evidence may include, but are not limited to, policy documents; revision history, records of review, or workflow evidence from a document management system that indicate review of each cyber security policy at least once every 15 calendar months; and documented approval by the CIP Senior Manager for each cyber security policy.

R2. Each Responsible Entity with at least one asset identified in CIP-002 containing low impact BES Cyber Systems shall implement one or more documented cyber security plan(s) for its low impact BES Cyber Systems that include the sections in Attachment 1. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

Note: An inventory, list, or discrete identification of low impact BES Cyber Systems or their BES Cyber Assets is not required. Lists of authorized users are not required.

M2. Evidence shall include each of the documented cyber security plan(s) that collectively include each of the sections in Attachment 1 and additional evidence to demonstrate implementation of the cyber security plan(s). Additional examples of evidence per section are located in Attachment 2.

R3. Each Responsible Entity shall identify a CIP Senior Manager by name and document any change within 30 calendar days of the change. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. An example of evidence may include, but is not limited to, a dated and approved document from a high level official designating the name of the individual identified as the CIP Senior Manager.

R4. The Responsible Entity shall implement a documented process to delegate authority, unless no delegations are used. Where allowed by the CIP Standards, the CIP Senior Manager may delegate authority for specific actions to a delegate or delegates. These delegations shall be documented, including the name or title of the delegate, the specific actions delegated, and the date of the delegation; approved by the CIP Senior Manager; and updated within 30 days of any change to the delegation. Delegation changes do not need to be reinstated with a change to the delegator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. An example of evidence may include, but is not limited to, a dated document, approved by the CIP Senior Manager, listing individuals (by name or title) who are delegated the authority to approve or authorize specifically identified items.

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 Responsible Entity 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:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar 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.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Investigations
- Self-Reporting
- Complaints

1.4. Additional Compliance Information:

None.

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7(i))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Operations Planning**	**Medium**	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address one of the nine topics required by R1. (R1.1) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 15 calendar months but did	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address two of the nine topics required by R1. (R1.1) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 16 calendar months but did	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address three of the nine topics required by R1. (R1.1) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 17 calendar months but did complete this review in less than or equal to 18	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address four or more of the nine topics required by R1. (R1.1) OR The Responsible Entity did not have any documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1. (R1.1) OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7(i))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			complete this review in less than or equal to 16 calendar months of the previous review. (R1.1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 15 calendar months but did complete this approval in less than or equal to 16 calendar months of the previous approval. (R1.1)	complete this review in less than or equal to 17 calendar months of the previous review. (R1.1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 16 calendar months but did complete this approval in less than or equal to 17 calendar months of the previous approval. (R1.1)	calendar months of the previous review. (R1.1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 17 calendar months but did complete this approval in less than or equal to 18 calendar months of the previous approval. (R1) OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact	The Responsible Entity did not complete its review of the one or more documented cyber security policies as required by R1 within 18 calendar months of the previous review. (R1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 18 calendar months of the previous approval. (R1.1)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7(i))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems, but did not address one of the six topics required by R1. (R1.2) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 within 15 calendar	OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems, but did not address two of the six topics required by R1. (R1.2) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 within 16 calendar	BES Cyber Systems, but did not address three of the six topics required by R1. (R1.2) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by R1 within 17 calendar months but did complete this review in less than or equal to 18 calendar months of the previous review. (R1.2) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its	OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems, but did not address four or more of the six topics required by R1. (R1.2) OR The Responsible Entity did not have any documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by R1. (R1.2) OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7(i))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			months but did complete this review in less than or equal to 16 calendar months of the previous review. (R1.2) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 15 calendar months but did complete this approval in less than or equal to 16 calendar months of	months but did complete this review in less than or equal to 17 calendar months of the previous review. (R1.2) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 16 calendar months but did complete this approval in less than or equal to 17	assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 17 calendar months but did complete this approval in less than or equal to 18 calendar months of the previous approval. (R1.2)	The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 18 calendar months of the previous approval. (R1.2)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7(i))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			the previous approval. (R1.2)	calendar months of the previous approval. (R1.2)		
R2	**Operations Planning**	**Lower**	The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document cyber security awareness according to Requirement R2, Attachment 1, Section 1. (R2) OR The Responsible Entity implemented electronic access controls but failed to document its cyber security plan(s) for electronic access controls according to Requirement R2,	The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to reinforce cyber security practices at least once every 15 calendar months according to Requirement R2, Attachment 1, Section 1. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed	The Responsible Entity documented the physical access controls for its assets containing low impact BES Cyber Systems, but failed to implement the physical security controls according to Requirement R2, Attachment 1, Section 2. (R2) OR The Responsible Entity documented its cyber security plan(s) for electronic access controls for its assets containing low impact BES Cyber Systems, but failed to permit only necessary inbound and outbound electronic	The Responsible Entity failed to document and implement one or more cyber security plan(s) for its assets containing low impact BES Cyber Systems according to Requirement R2, Attachment 1. (R2)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7(i))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Attachment 1, Section 3. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document one or more Cyber Security Incident response plan(s) according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented one or more Cyber Security Incident response plan(s) within its cyber security plan(s) for its assets containing	to document physical security controls according to Requirement R2, Attachment 1, Section 2. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document electronic access controls according to Requirement R2, Attachment 1, Section 3. (R2) OR The Responsible Entity documented its cyber security plan(s) for electronic access controls but	access controls according to Requirement R2, Attachment 1, Section 3.1. (R2) OR The Responsible Entity documented one or more Cyber Security Incident response plan(s) within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to test each Cyber Security Incident response plan(s) at least once every 36 calendar months according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented the determination of	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7(i))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			low impact BES Cyber Systems, but failed to update each Cyber Security Incident response plan(s) within 180 days according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to manage its Transient Cyber Asset(s) according to Requirement R2, Attachment 1, Section 5.1. (R2) OR The Responsible Entity documented	failed to implement authentication for all Dial-up Connectivity that provides access to low impact BES Cyber System(s), per Cyber Asset capability according to Requirement R2, Attachment 1, Section 3.2 (R2) OR The Responsible Entity documented one or more incident response plan(s) within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to include the process for identification, classification, and response to Cyber Security Incidents	whether an identified Cyber Security Incident is a Reportable Cyber Security Incident, but failed to notify the Electricity Information Sharing and Analysis Center (E-ISAC) according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to implement mitigation for the introduction of malicious code for Transient Cyber Assets managed by the Responsible Entity according to Requirement R2,	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7(i))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			its plan(s) for Transient Cyber Assets ~~and Removable Media~~, but failed to document the Removable Media section(s) according to Requirement R2, Attachment 1, Section 5.3. (R2)	according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document the determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and subsequent notification to the Electricity Information Sharing and Analysis Center (E-ISAC) according to Requirement R2,	Attachment 1, Section 5.1. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to implement mitigation for the introduction of malicious code for Transient Cyber Assets managed by a party other than the Responsible Entity according to Requirement R2, Attachment 1, Section 5.2. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to implement mitigation for	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7(i))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				Attachment 1, Section 4. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to document mitigation for the introduction of malicious code for Transient Cyber Assets managed by the Responsible Entity according to Requirement R2, Attachment 1, Sections 5.1 and 5.3. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber	the threat of detected malicious code on the Removable Media prior to connecting Removable Media to a low impact BES Cyber System according to Requirement R2, Attachment 1, Section 5.3. (R2)	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7(i))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				Assets and Removable Media, but failed to document mitigation for the introduction of malicious code for Transient Cyber Assets managed by a party other than the Responsible Entity according to Requirement R2, Attachment 1, Section 5.2. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to implement the Removable Media section(s) according to Requirement R2,		

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7(i))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				Attachment 1, Section 5.3. (R2)		
R3	Operations Planning	Medium	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 30 calendar days but did document this change in less than 40 calendar days of the change. (R3)	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 40 calendar days but did document this change in less than 50 calendar days of the change. (R3)	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 50 calendar days but did document this change in less than 60 calendar days of the change. (R3)	The Responsible Entity has not identified, by name, a CIP Senior Manager. OR The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 60 calendar days of the change. (R3)
R4	Operations Planning	Lower	The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did	The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did	The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate	The Responsible Entity has used delegated authority for actions where allowed by the CIP Standards, but does not have a process

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7(i))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			not document changes to the delegate within 30 calendar days but did document this change in less than 40 calendar days of the change. (R4)	not document changes to the delegate within 40 calendar days but did document this change in less than 50 calendar days of the change. (R4)	within 50 calendar days but did document this change in less than 60 calendar days of the change. (R4)	to delegate actions from the CIP Senior Manager. (R4) OR The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 60 calendar days of the change. (R4)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

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Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated Version Number from -2 to -3 In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009.	
3	12/16/09	Approved by the NERC Board of Trustees.	
3	3/31/10	Approved by FERC.	
4	1/24/11	Approved by the NERC Board of Trustees.	
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5	11/22/13	FERC Order issued approving CIP-003-5.	

Version	Date	Action	Change Tracking
6	11/13/14	Adopted by the NERC Board of Trustees.	Addressed two FERC directives from Order No. 791 related to identify, assess, and correct language and communication networks.
6	2/12/15	Adopted by the NERC Board of Trustees.	Replaces the version adopted by the Board on 11/13/2014. Revised version addresses remaining directives from Order No. 791 related to transient devices and low impact BES Cyber Systems.
6	1/21/16	FERC Order issued approving CIP-003-6. Docket No. RM15-14-000	
7(i)	TBD	Adopted by the NERC Board of Trustees.	Revised to address FERC Order No. 822 directives regarding (1) the definition of LERC and (2) transient devices.

Attachment 1

Required Sections for Cyber Security Plan(s) for Assets Containing Low Impact BES Cyber Systems

Responsible Entities shall include each of the sections provided below in the cyber security plan(s) required under Requirement R2.

Responsible Entities with multiple-impact BES Cyber Systems ratings can utilize policies, procedures, and processes for their high or medium impact BES Cyber Systems to fulfill the sections for the development of low impact cyber security plan(s). Each Responsible Entity can develop a cyber security plan(s) either by individual asset or groups of assets.

Section 1. Cyber Security Awareness: Each Responsible Entity shall reinforce, at least once every 15 calendar months, cyber security practices (which may include associated physical security practices).

Rationale for Modifications to Sections 2 and 3 of Attachment 1 (Requirement R2):

Requirement R2 mandates that entities develop and implement one or more cyber security plan(s) to meet specific security objectives for assets containing low impact BES Cyber System(s). In Paragraph 73 of FERC Order No. 822, the Commission directed NERC to modify "…the Low Impact External Routable Connectivity definition to reflect the commentary in the Guidelines and Technical Basis section of CIP-003-6…to provide needed clarity to the definition and eliminate ambiguity surrounding the term 'direct' as it is used in the proposed definition…within one year of the effective date of this Final Rule."

The revisions to Section 3 incorporate select language from the LERC definition into Attachment 1 and focus the requirement on implementing electronic access controls for asset(s) containing low impact BES Cyber System(s). This change requires the Responsible Entity to permit only necessary inbound and outbound electronic access when using a routable protocol entering or leaving the asset between low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing low impact BES Cyber system(s). When this communication is present, Responsible Entities are required to implement electronic access controls unless that communication meets the following exclusion language (previously in the definition of LERC) contained in romanette (iii): "not used for time-sensitive protection or control functions between intelligent electronic devices (e.g. communications using protocol IEC TR-61850-90-5 R-GOOSE)".

The revisions to Section 2 of Attachment 1 complement the revisions to Section 3; consequently, the requirement now mandates the Responsible Entity control physical access to "the Cyber Asset(s), as specified by the Responsible Entity, that provide electronic access control(s) implemented for Section 3.1, if any." The focus on electronic access controls rather than on the Low Impact BES Cyber System Electronic Access Points (LEAPs) eliminates the need for LEAPs.

Given these revisions to Sections 2 and 3, the NERC Glossary terms: Low Impact External Routable Connectivity (LERC) and Low Impact BES Cyber System Electronic Access Point (LEAP) will be retired.

Section 2. Physical Security Controls: Each Responsible Entity shall control physical access, based on need as determined by the Responsible Entity, to (1) the asset or the locations of the low impact BES Cyber Systems within the asset, and (2) the Cyber Asset(s), as specified by the Responsible Entity, that provide electronic access control(s) implemented for Section 3.1, if any.

Section 3. Electronic Access Controls: For each asset containing low impact BES Cyber System(s) identified pursuant to CIP-002, the Responsible Entity shall implement electronic access controls to:

3.1 Permit only necessary inbound and outbound electronic access as determined by the Responsible Entity for any communications that are:

i. between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing low impact BES Cyber System(s);

ii. using a routable protocol when entering or leaving the asset containing the low impact BES Cyber System(s); and

iii. not used for time-sensitive protection or control functions between intelligent electronic devices (e.g., communications using protocol IEC TR-61850-90-5 R-GOOSE).

3.2 Authenticate all Dial-up Connectivity, if any, that provides access to low impact BES Cyber System(s), per Cyber Asset capability.

Section 4. Cyber Security Incident Response: Each Responsible Entity shall have one or more Cyber Security Incident response plan(s), either by asset or group of assets, which shall include:

4.1 Identification, classification, and response to Cyber Security Incidents;

4.2 Determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and subsequent notification to the Electricity Information Sharing and Analysis Center (E-ISAC), unless prohibited by law;

4.3 Identification of the roles and responsibilities for Cyber Security Incident response by groups or individuals;

4.4 Incident handling for Cyber Security Incidents;

4.5 Testing the Cyber Security Incident response plan(s) at least once every 36 calendar months by: (1) responding to an actual Reportable Cyber Security

Incident; (2) using a drill or tabletop exercise of a Reportable Cyber Security Incident; or (3) using an operational exercise of a Reportable Cyber Security Incident; and

4.6 Updating the Cyber Security Incident response plan(s), if needed, within 180 calendar days after completion of a Cyber Security Incident response plan(s) test or actual Reportable Cyber Security Incident.

Rationale for Section 5 of Attachment 1 (Requirement R2):

Requirement R2 mandates that entities develop and implement one or more cyber security plan(s) to meet specific security objectives for assets containing low impact BES Cyber System(s). In Paragraph 32 of FERC Order No. 822, the Commission directed NERC to "…provide mandatory protection for transient devices used at Low Impact BES Cyber Systems based on the risk posed to bulk electric system reliability." Transient devices are potential vehicles for introducing malicious code into low impact BES Cyber Systems. Section 5 of Attachment 1 is intended to mitigate the risk of malware propagation to the BES through low impact BES Cyber Systems by requiring entities to develop and implement one or more plan(s) to address the risk. The cyber security plan(s) along with the cyber security policies required under Requirement R1, Part 1.2, provide a framework for operational, procedural, and technical safeguards for low impact BES Cyber Systems.

Section 5. Transient Cyber Asset and Removable Media Malicious Code Risk Mitigation: -Each Responsible Entity shall implement, except under CIP Exceptional Circumstances, one or more plan(s) to achieve the objective of mitigating the risk of the introduction of malicious code to low impact BES Cyber Systems through the use of Transient Cyber Assets or Removable Media. The plan(s) shall include:

5.1 For Transient Cyber Asset(s) managed by the Responsible Entity, if any, the use of one or a combination of the following in an ongoing or on-demand manner (per Transient Cyber Asset capability):

- Antivirus software, including manual or managed updates of signatures or patterns;
- Application whitelisting; or
- Other method(s) to mitigate the introduction of malicious code.

5.2 For Transient Cyber Asset(s) managed by a party other than the Responsible Entity, if any, the use of one or a combination of the following prior to connecting the Transient Cyber Asset to a low impact BES Cyber System (per Transient Cyber Asset capability):

- Review of antivirus update level;
- Review of antivirus update process used by the party;

- Review of application whitelisting used by the party;
- Review use of live operating system and software executable only from read-only media;
- Review of system hardening used by the party; or
- Other method(s) to mitigate the introduction of malicious code.

5.3 For Removable Media, the use of each of the following:

5.3.1 Method(s) to detect malicious code on Removable Media using a Cyber Asset other than a BES Cyber System; and

5.3.2 Mitigation of the threat of detected malicious code on the Removable Media prior to connecting Removable Media to a low impact BES Cyber System.

Attachment 2

Examples of Evidence for Cyber Security Plan(s) for Assets Containing Low Impact BES Cyber Systems

Section 1. Cyber Security Awareness: An example of evidence for Section 1 may include, but is not limited to, documentation that the reinforcement of cyber security practices occurred at least once every 15 calendar months. The evidence could be documentation through one or more of the following methods:

- Direct communications (for example, e-mails, memos, or computer-based training);
- Indirect communications (for example, posters, intranet, or brochures); or
- Management support and reinforcement (for example, presentations or meetings).

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Section 2. Physical Security Controls: Examples of evidence for Section 2 may include, but are not limited to:

- Documentation of the selected access control(s) (e.g., card key, locks, perimeter controls), monitoring controls (e.g., alarm systems, human observation), or other operational, procedural, or technical physical security controls that control physical access to both:
  a. The asset, if any, or the locations of the low impact BES Cyber Systems within the asset; and
  b. The Cyber Asset(s) specified by the Responsible Entity that provide(s) electronic access controls implemented for Attachment 1, Section 3.1, if any.

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Section 3. Electronic Access Controls: Examples of evidence for Section 3 may include, but are not limited to:

1. Documentation showing that at each asset or group of assets containing low impact BES Cyber Systems, routable communication between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset is restricted by electronic access controls to permit only inbound and outbound electronic access that the Responsible Entity deems necessary, except where an entity provides rationale that communication is used for time-sensitive protection or control functions between intelligent electronic devices. Examples of such documentation may include, but are not limited to representative diagrams that illustrate control of inbound and outbound communication(s) between the low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing low impact BES Cyber System(s) or lists of implemented electronic access controls (e.g., access control lists restricting IP addresses, ports, or services; implementing unidirectional gateways).

2. Documentation of authentication for Dial-up Connectivity (e.g., dial out only to a preprogrammed number to deliver data, dial-back modems, modems that must be remotely controlled by the control center or control room, or access control on the BES Cyber System).

Section 4. Cyber Security Incident Response: An example of evidence for Section 4 may include, but is not limited to, dated documentation, such as policies, procedures, or process documents of one or more Cyber Security Incident response plan(s) developed either by asset or group of assets that include the following processes:

1. to identify, classify, and respond to Cyber Security Incidents; to determine whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and for notifying the Electricity Information Sharing and Analysis Center (E-ISAC);
2. to identify and document the roles and responsibilities for Cyber Security Incident response by groups or individuals (e.g., initiating, documenting, monitoring, reporting, etc.);
3. for incident handling of a Cyber Security Incident (e.g., containment, eradication, or recovery/incident resolution);
4. for testing the plan(s) along with the dated documentation that a test has been completed at least once every 36 calendar months; and
5. to update, as needed, Cyber Security Incident response plan(s) within 180 calendar days after completion of a test or actual Reportable Cyber Security Incident.

Section 5. Transient Cyber Asset and Removable Media Malicious Code Risk Mitigation:

1. Examples of evidence for Section 5.1 may include, but are not limited to, documentation of the method(s) used to mitigate the introduction of malicious code such as antivirus software and processes for managing signature or pattern updates, application whitelisting practices, processes to restrict communication, or other method(s) to mitigate the introduction of malicious code. If a Transient Cyber Asset does not have the capability to use method(s) that mitigate the introduction of malicious code, evidence may include documentation by the vendor or Responsible Entity that identifies that the Transient Cyber Asset does not have the capability.
2. Examples of evidence for Section 5.2 may include, but are not limited to, documentation from change management systems, electronic mail or procedures that document a review of the installed antivirus update level; memoranda, electronic mail, system documentation, policies or contracts from the party other than the Responsible Entity that identify the antivirus update process, the use of application whitelisting, use of live operating systems or system hardening performed by the party other than the Responsible Entity; evidence from change management systems, electronic mail or contracts that

identifies the Responsible Entity's acceptance that the practices of the party other than the Responsible Entity are acceptable; or documentation of other method(s) to mitigate malicious code for Transient Cyber Asset(s) managed by a party other than the Responsible Entity. If a Transient Cyber Asset does not have the capability to use method(s) that mitigate the introduction of malicious code, evidence may include documentation by the Responsible Entity or the party other than the Responsible Entity that identifies that the Transient Cyber Asset does not have the capability

3. Examples of evidence for Section 5.3.1 may include, but are not limited to, documented process(es) of the method(s) used to detect malicious code such as results of scan settings for Removable Media, or implementation of on-demand scanning. Examples of evidence for Section 5.3.2 may include, but are not limited to, documented process(es) for the method(s) used for mitigating the threat of detected malicious code on Removable Media, such as logs from the method(s) used to detect malicious code that show the results of scanning and the mitigation of detected malicious code on Removable Media or documented confirmation by the entity that the Removable Media was deemed to be free of malicious code.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section "4. Applicability" of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section "4.1. Functional Entities" is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section "4.2. Facilities" defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term "Facilities" already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

Requirement R1:

In developing policies in compliance with Requirement R1, the number of policies and their content should be guided by a Responsible Entity's management structure and operating conditions. Policies might be included as part of a general information security program for the entire organization, or as components of specific programs. The Responsible Entity has the flexibility to develop a single comprehensive cyber security policy covering the required topics, or it may choose to develop a single high-level umbrella policy and provide additional policy detail in lower level documents in its documentation hierarchy. In the case of a high-level umbrella policy, the Responsible Entity would be expected to provide the high-level policy as well as the additional documentation in order to demonstrate compliance with CIP-003-7, Requirement R1.

If a Responsible Entity has any high or medium impact BES Cyber Systems, the one or more cyber security policies must cover the nine subject matter areas required by CIP-003-7, Requirement R1, Part 1.1. If a Responsible Entity has identified from CIP-002 any assets containing low impact BES Cyber Systems, the one or more cyber security policies must cover the six subject matter areas required by Requirement R1, Part 1.2.

Responsible Entities that have multiple-impact rated BES Cyber Systems are not required to create separate cyber security policies for high, medium, or low impact BES Cyber Systems. The Responsible Entities have the flexibility to develop policies that cover all three impact ratings.

Implementation of the cyber security policy is not specifically included in CIP-003-7, Requirement R1 as it is envisioned that the implementation of this policy is evidenced through successful implementation of CIP-003 through CIP-011. However, Responsible Entities are encouraged not to limit the scope of their cyber security policies to only those requirements in NERC cyber security Reliability Standards, but to develop a holistic cyber security policy appropriate for its organization. Elements of a policy that extend beyond the scope of NERC's cyber security Reliability Standards will not be considered candidates for potential violations although they will help demonstrate the organization's internal culture of compliance and posture towards cyber security.

For Part 1.1, the Responsible Entity ~~should~~ may consider the following for each of the required topics in its one or more cyber security policies for medium and high impact BES Cyber Systems, if any:

1.1.1 Personnel and training (CIP-004)

- Organization position on acceptable background investigations
- Identification of possible disciplinary action for violating this policy
- Account management

1.1.2 Electronic Security Perimeters (CIP-005) including Interactive Remote Access

- Organization stance on use of wireless networks
- Identification of acceptable authentication methods
- Identification of trusted and untrusted resources
- Monitoring and logging of ingress and egress at Electronic Access Points
- Maintaining up-to-date anti-malware software before initiating Interactive Remote Access
- Maintaining up-to-date patch levels for operating systems and applications used to initiate Interactive Remote Access
- Disabling VPN "split-tunneling" or "dual-homed" workstations before initiating Interactive Remote Access
- For vendors, contractors, or consultants: include language in contracts that requires adherence to the Responsible Entity's Interactive Remote Access controls

1.1.3 Physical security of BES Cyber Systems (CIP-006)

- Strategy for protecting Cyber Assets from unauthorized physical access
- Acceptable physical access control methods
- Monitoring and logging of physical ingress

1.1.4 System security management (CIP-007)

- Strategies for system hardening
- Acceptable methods of authentication and access control
- Password policies including length, complexity, enforcement, prevention of brute force attempts
- Monitoring and logging of BES Cyber Systems

1.1.5 Incident reporting and response planning (CIP-008)

- Recognition of Cyber Security Incidents
- Appropriate notifications upon discovery of an incident
- Obligations to report Cyber Security Incidents

1.1.6 Recovery plans for BES Cyber Systems (CIP-009)

- Availability of spare components
- Availability of system backups

1.1.7 Configuration change management and vulnerability assessments (CIP-010)

- Initiation of change requests
- Approval of changes
- Break-fix processes

1.1.8 Information protection (CIP-011)

- Information access control methods
- Notification of unauthorized information disclosure
- Information access on a need-to-know basis

1.1.9 Declaring and responding to CIP Exceptional Circumstances

- Processes to invoke special procedures in the event of a CIP Exceptional Circumstance
- Processes to allow for exceptions to policy that do not violate CIP requirements

For Part 1.2, the Responsible Entity may consider the following for each of the required topics in its one or more cyber security policies for assets containing low impact BES Cyber Systems, if any:

1.2.1 Cyber security awareness

- Method(s) for delivery of security awareness
- Identification of groups to receive cyber security awareness

1.2.2 Physical security controls

- Acceptable approach(es) for selection of physical security control(s)

1.2.3 Electronic access controls

- Acceptable approach(es) for selection of electronic access control(s)

1.2.4 Cyber Security Incident response

- Recognition of Cyber Security Incidents

- Appropriate notifications upon discovery of an incident
- Obligations to report Cyber Security Incidents

1.2.5 Transient Cyber Assets and Removable Media Malicious Code Risk Mitigation

- Acceptable use of Transient Cyber Asset(s) and Removable Media
- Method(s) to mitigate the risk of the introduction of malicious code to low impact BES Cyber Systems from Transient Cyber Assets and Removable Media
- Method(s) to request Transient Cyber Asset and Removable Media

1.2.6 Declaring and responding to CIP Exceptional Circumstances

- Process(es) to declare a CIP Exceptional Circumstance
- Process(es) to respond to a declared CIP Exceptional Circumstance

Requirements relating to exceptions to a Responsible Entity's security policies were removed because it is a general management issue that is not within the scope of a reliability requirement. It is an internal policy requirement and not a reliability requirement. However, Responsible Entities are encouraged to continue this practice as a component of their cyber security policies.

In this and all subsequent required approvals in the NERC CIP Reliability Standards, the Responsible Entity may elect to use hardcopy or electronic approvals to the extent that there is sufficient evidence to ensure the authenticity of the approving party.

Requirement R2:

The intent of Requirement R2 is for each Responsible Entity to create, document, and implement one or more cyber security plan(s) that address the security objective for the protection of low impact BES Cyber Systems. The required protections are designed to be part of a program that covers the low impact BES Cyber Systems collectively at an asset level (based on the list of assets containing low impact BES Cyber Systems identified in CIP-002), but not at an individual device or system level.

Requirement R2, Attachment 1

As noted, Attachment 1 contains the sections that must be included in the cyber security plan(s). The intent is to allow entities that have a combination of high, medium, and low impact BES Cyber Systems the flexibility to choose, if desired, to cover their low impact BES Cyber Systems (or any subset) under their programs used for the high or medium impact BES Cyber Systems rather than maintain two separate programs. The purpose of the cyber security plan(s) in Requirement R2 is for Responsible Entities to use the cyber security plan(s) as a means of documenting their approaches to meeting the subject matter areas. The cyber security plan(s) can be used to reference other policies and procedures that demonstrate "how" the Responsible Entity is meeting each of the subject matter areas, or Responsible Entities can develop comprehensive cyber security plan(s) that contain all of the detailed implementation content solely within the cyber security plan itself. To meet the obligation for the cyber security plan, the expectation is that the cyber security plan contains or references sufficient details to address the implementation of each of the required subject matters areas.

Guidance for each of the subject matter areas of Attachment 1 is provided below.

Requirement R2, Attachment 1, Section 1 – Cyber Security Awareness

The intent of the cyber security awareness program is for entities to reinforce good cyber security practices with their personnel at least once every 15 calendar months. The entity has the discretion to determine the topics to be addressed and the manner in which it will communicate these topics. As evidence of compliance, the Responsible Entity should be able to produce the awareness material that was delivered according to the delivery method(s) (e.g., posters, emails, or topics at staff meetings, etc.). The standard drafting team does not intend for Responsible Entities to be required to maintain lists of recipients and track the reception of the awareness material by personnel.

Although the focus of the awareness is cyber security, it does not mean that only technology-related topics can be included in the program. Appropriate physical security topics (e.g., tailgating awareness and protection of badges for physical security, or "If you see something, say something" campaigns, etc.) are valid for cyber security awareness. The intent is to cover topics concerning any aspect of the protection of BES Cyber Systems.

Requirement R2, Attachment 1, Section 2 – Physical Security Controls

The Responsible Entity must document and implement methods to control physical access to (1) the asset or the locations of low impact BES Cyber Systems within the asset, and (2) Cyber Assets that implement the electronic access control(s) specified by the Responsible Entity in Attachment 1, Section 3.1, if any. If these Cyber Assets implementing the electronic access controls are located within the same asset as the low impact BES Cyber Asset(s) and inherit the same physical access controls and the same need as outlined in Section 2, this may be noted by the Responsible Entity in either its policies or cyber security plan(s) to avoid duplicate documentation of the same controls.

The Responsible Entity has the flexibility to select the methods used to meet the objective of controlling physical access to (1) the asset(s) containing low impact BES Cyber System(s) or the low impact BES Cyber Systems themselves and (2) the electronic access control Cyber Assets specified by the Responsible Entity, if any. The Responsible Entity may use one or a combination of physical access controls, monitoring controls, or other operational, procedural, or technical physical security controls. Entities may use perimeter controls (e.g., fences with locked gates, guards, or site access policies, etc.) or more granular areas of physical access control in areas where low impact BES Cyber Systems are located, such as control rooms or control houses.

The security objective is to control the physical access based on need as determined by the Responsible Entity. The need for physical access can be documented at the policy level. The standard drafting team did not intend to obligate an entity to specify a need for each physical access or authorization of an individual for physical access.

Monitoring as a physical security control can be used as a complement or an alternative to physical access control. Examples of monitoring controls include, but are not limited to: (1) alarm systems to detect motion or entry into a controlled area, or (2) human observation of a controlled area. Monitoring does not necessarily require logging and maintaining logs but could include monitoring that physical access has occurred or been attempted (e.g., door alarm, or human observation, etc.). The standard drafting team's intent is that the monitoring does not need to be per low impact BES Cyber System but should be at the appropriate level to meet the security objective of controlling physical access.

User authorization programs and lists of authorized users for physical access are not required although they are an option to meet the security objective.

Requirement R2, Attachment 1, Section 3 – Electronic Access Controls

Section 3 requires the establishment of electronic access controls for assets containing low impact BES Cyber Systems when there is routable protocol communication or Dial-up Connectivity between Cyber Asset(s) outside of the asset containing the low impact BES Cyber System(s) and the low impact BES Cyber System(s) within such asset. The establishment of electronic access controls is intended to reduce the risks associated with uncontrolled communication using routable protocols or Dial-up Connectivity.

When implementing Attachment 1, Section 3.1, Responsible Entities should note that electronic access controls to permit only necessary inbound and outbound electronic access are required for communications when those communications meet all three of the criteria identified in Attachment 1, Section 3.1. The Responsible Entity should evaluate the communications and when all three criteria are met, the Responsible Entity must document and implement electronic access control(s).

When identifying electronic access controls, Responsible Entities are provided flexibility in the selection of the electronic access controls that meet their operational needs while meeting the security objective of allowing only necessary inbound and outbound electronic access to low impact BES Cyber Systems that use routable protocols between a low impact BES Cyber System(s) and Cyber Asset(s) outside the asset.

In essence, the intent is for Responsible Entities to determine whether there is communication between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing low impact BES Cyber System(s) that uses a routable protocol when entering or leaving the asset or Dial-up Connectivity to the low impact BES Cyber System(s). Where such communication is present, Responsible Entities should document and implement electronic access control(s). Where routable protocol communication for time-sensitive protection or control functions between intelligent electronic devices that meets the exclusion language is present, Responsible Entities should document that communication, but are not required to establish any specific electronic access controls.

The inputs to this requirement are the assets identified in CIP-002 as containing low impact BES Cyber System(s); therefore, the determination of routable protocol communications or Dial-up Connectivity is an attribute of the asset. However, it is not intended for communication that provides no access to or from the low impact BES Cyber System(s), but happens to be located at the asset with the low impact BES Cyber System(s), to be evaluated for electronic access controls.

Electronic Access Control Exclusion

In order to avoid future technology issues, the obligations for electronic access controls exclude communications between intelligent electronic devices that use routable communication protocols for time-sensitive protection or control functions, such as IEC TR-61850-90-5 R-GOOSE messaging. Time-sensitive in this context generally means functions that would be negatively impacted by the latency introduced in the communications by the required electronic access controls. This time-sensitivity exclusion does not apply to SCADA communications which typically operate on scan rates of 2 seconds or greater. While technically time-sensitive, SCADA communications over routable protocols can withstand the delay introduced by electronic access controls. Examples of excluded time-sensitive communications are those communications which may necessitate the tripping of a breaker within a few cycles. A Responsible Entity using this technology is not expected to implement the electronic access controls noted herein. This exception was included so as not to inhibit the functionality of the time-sensitive characteristics related to this technology and not to preclude the use of such time-sensitive reliability enhancing functions if they use a routable protocol in the future.

Considerations for Determining Routable Protocol Communications

To determine whether electronic access controls need to be implemented, the Responsible Entity has to determine whether there is communication between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing the low impact BES Cyber System(s) that uses a routable protocol when entering or leaving the asset.

When determining whether a routable protocol is entering or leaving the asset containing the low impact BES Cyber System(s), Responsible Entities have flexibility in identifying an approach. One approach is for Responsible Entities to identify an “electronic boundary” associated with the asset containing low impact BES Cyber System(s). This is not an Electronic Security Perimeter *per se*, but a demarcation that demonstrates the routable protocol communication entering or leaving the asset between a low impact BES Cyber System and Cyber Asset(s) outside the asset to then have electronic access controls implemented. This electronic boundary may vary by asset type (Control Center, substation, generation resource) and the specific configuration of the asset. If this approach is used, the intent is for the Responsible Entity to define the electronic boundary such that the low impact BES Cyber System(s) located at the asset are contained within the "electronic boundary." This is strictly for determining which routable protocol communications and networks are internal or inside or local to the asset and which are external to or outside the asset.

Alternatively, the Responsible Entity may find the concepts of what is inside and outside to be intuitively obvious for a Cyber Asset(s) outside the asset containing low impact BES Cyber System(s) communicating to a low impact BES Cyber System(s) inside the asset. This may be the case when a low impact BES Cyber System(s) is communicating with a Cyber Asset many miles away and a clear and unambiguous demarcation exists. In this case, a Responsible Entity may decide not to identify an "electronic boundary," but rather to simply leverage the unambiguous asset demarcation to ensure that the electronic access controls are placed between the low impact BES Cyber System(s) and the Cyber Asset(s) outside the asset.

Determining Electronic Access Controls

Once a Responsible Entity has determined that there is routable communication between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing the low impact BES Cyber System(s) that uses a routable protocol when entering or leaving the asset containing the low impact BES Cyber System(s), the intent is for the Responsible Entity to document and implement its chosen electronic access control(s). The control(s) are intended to allow only "necessary" inbound and outbound electronic access as determined by the Responsible Entity. However the Responsible Entity chooses to document the inbound and outbound access permissions and the need, the intent is that the Responsible Entity is able to explain the reasons for the electronic access permitted. The reasoning for "necessary" inbound and outbound electronic access controls may be documented within the Responsible Entity's cyber security plan(s), within a comment on an access control list, a database, spreadsheet or other policies or procedures associated with the electronic access controls.

Concept Diagrams

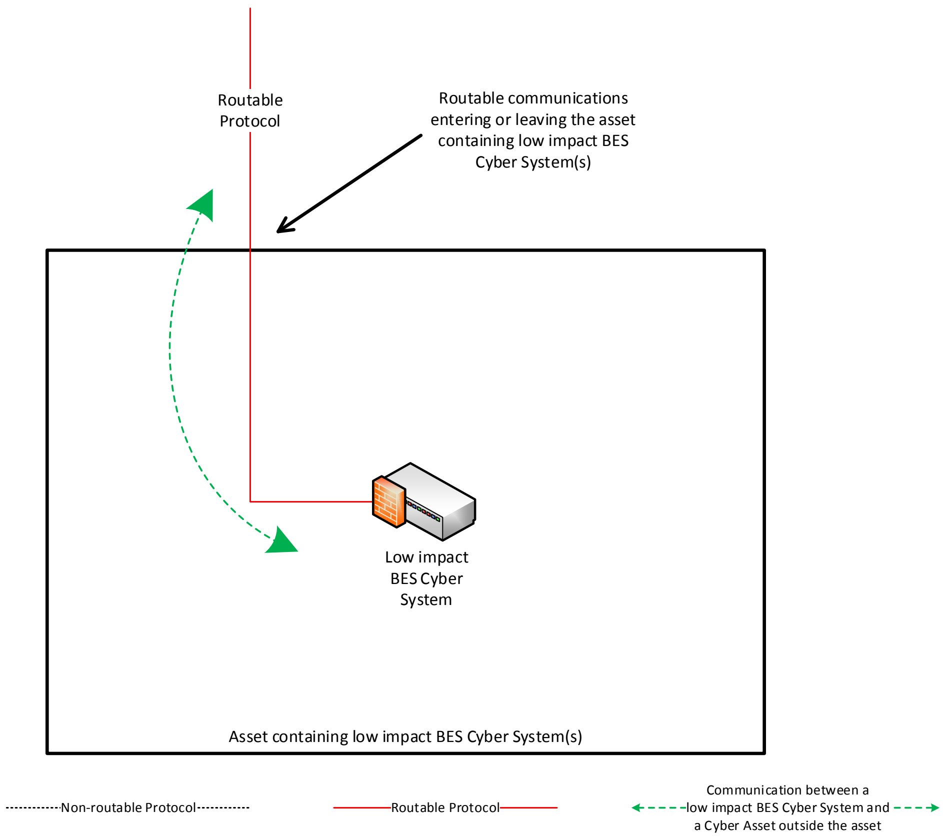
The diagrams on the following pages are provided as examples to illustrate various electronic access controls at a conceptual level. Regardless of the concepts or configurations chosen by the Responsible Entity, the intent is to achieve the security objective of permitting only necessary inbound and outbound electronic access for communication between low impact BES Cyber Systems and Cyber Asset(s) outside the asset containing the low impact BES Cyber System(s) using a routable protocol when entering or leaving the asset.

NOTE:

- This is not an exhaustive list of applicable concepts.
- The same legend is used in each diagram; however, the diagram may not contain all of the articles represented in the legend.

Reference Model 1 – Host-based Inbound & Outbound Access Permissions

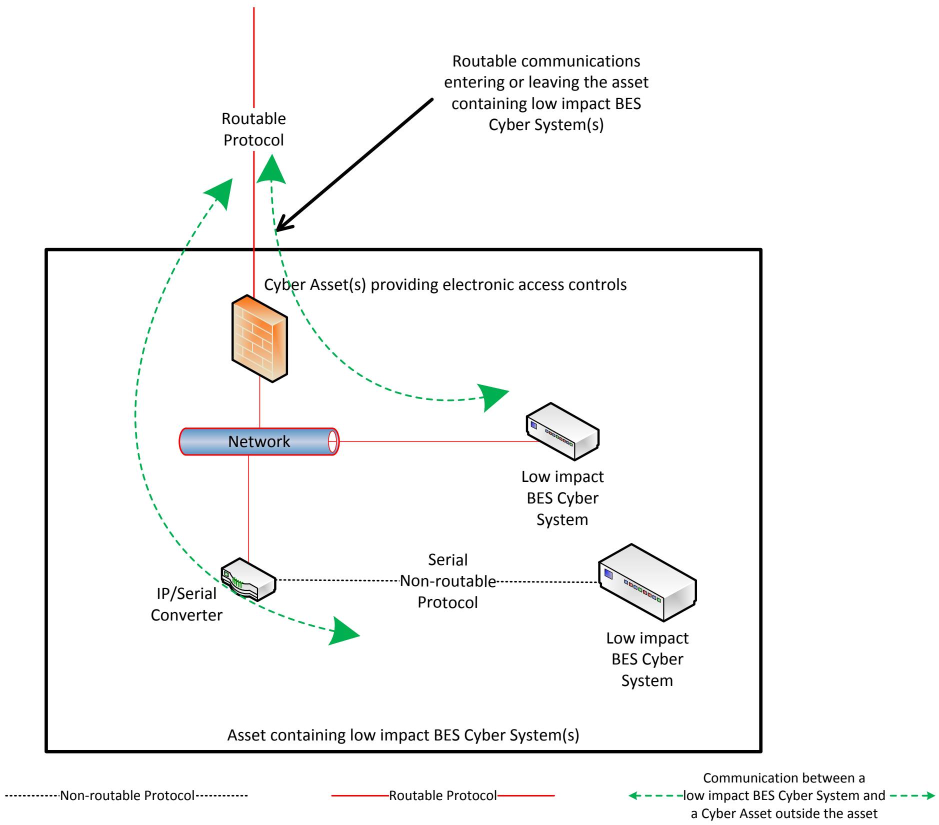
The Responsible Entity may choose to utilize a host-based firewall technology on the low impact BES Cyber System(s) itself that manages the inbound and outbound electronic access permissions so that only necessary inbound and outbound electronic access is allowed between the low impact BES Cyber System(s) and the Cyber Asset(s) outside the asset containing the low impact BES Cyber System(s). When permitting the inbound and outbound electronic access permissions using access control lists, the Responsible Entity could restrict communication(s) using source and destination addresses or ranges of addresses. Responsible Entities could also restrict communication(s) using ports or services based on the capability of the electronic access control, the low impact BES Cyber System(s), or the application(s).



Reference Model 1

Reference Model 2 – Network-based Inbound & Outbound Access Permissions

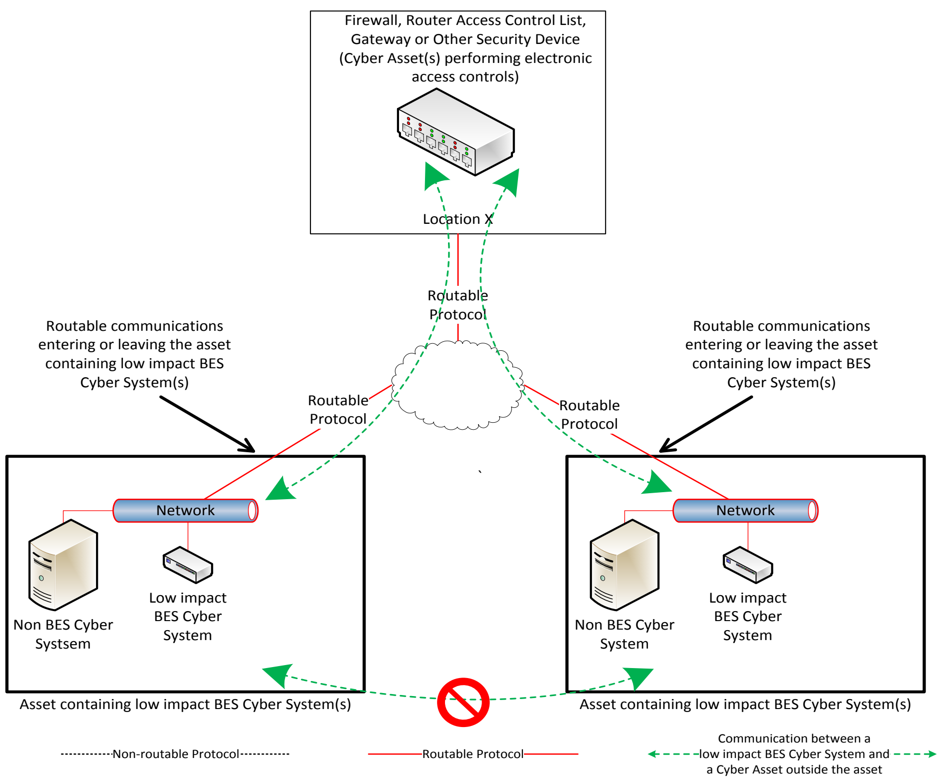
The Responsible Entity may choose to use a security device that permits only necessary inbound and outbound electronic access to the low impact BES Cyber System(s) within the asset containing the low impact BES Cyber System(s). In this example, two low impact BES Cyber Systems are accessed using the routable protocol that is entering or leaving the asset containing the low impact BES Cyber System(s). The IP/Serial converter is continuing the same communications session from the Cyber Asset(s) that are outside the asset to the low impact BES Cyber System(s). The security device provides the electronic access controls to permit only necessary inbound and outbound routable protocol access to the low impact BES Cyber System(s). When permitting the inbound and outbound electronic access permissions using access control lists, the Responsible Entity could restrict communication(s) using source and destination addresses or ranges of addresses. Responsible Entities could also restrict communication(s) using ports or services based on the capability of the electronic access control, the low impact BES Cyber System(s), or the application(s).



Reference Model 2

Reference Model 3 – Centralized Network-based Inbound & Outbound Access Permissions

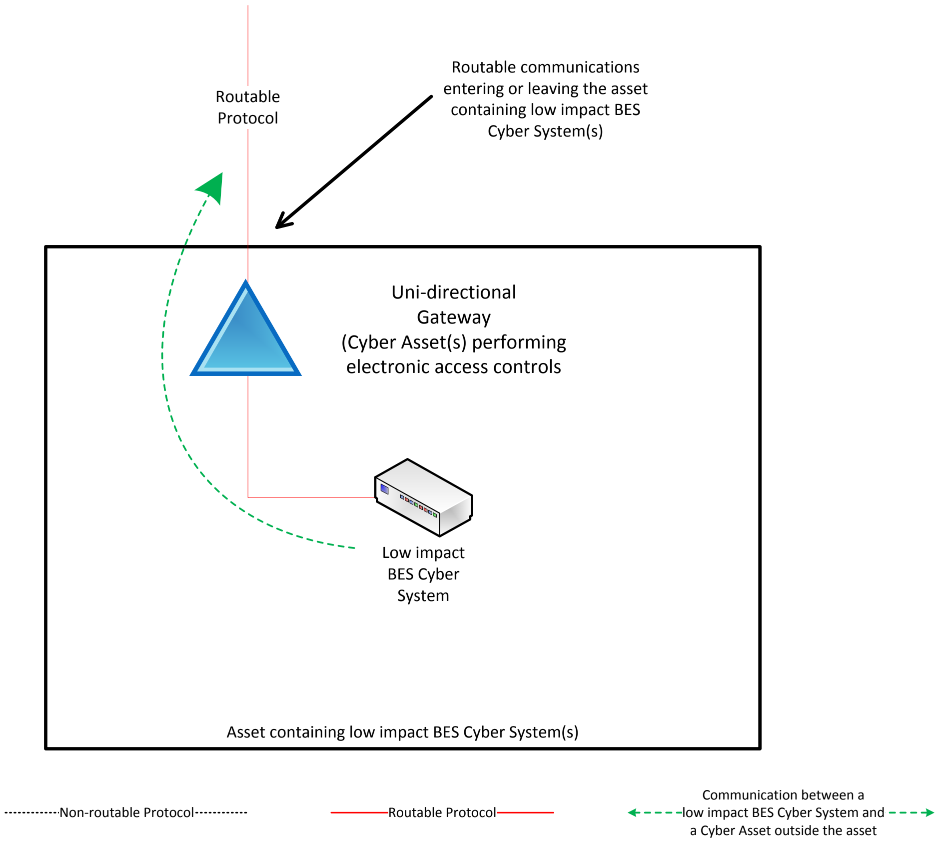
The Responsible Entity may choose to utilize a security device at a centralized location that may or may not be at another asset containing low impact BES Cyber System(s). The electronic access control(s) do not necessarily have to reside inside the asset containing the low impact BES Cyber System(s). A security device is in place at "Location X" to act as the electronic access control and permit only necessary inbound and outbound routable protocol access between the low impact BES Cyber System(s) and the Cyber Asset(s) outside each asset containing low impact BES Cyber System(s). Care should be taken that electronic access to or between each asset is through the Cyber Asset(s) determined by the Responsible Entity to be performing electronic access controls at the centralized location. When permitting the inbound and outbound electronic access permissions using access control lists, the Responsible Entity could restrict communication(s) using source and destination addresses or ranges of addresses. Responsible Entities could also restrict communication(s) using ports or services based on the capability of the electronic access control, the low impact BES Cyber System(s), or the application(s).



Reference Model 3

Reference Model 4 – Uni-directional Gateway

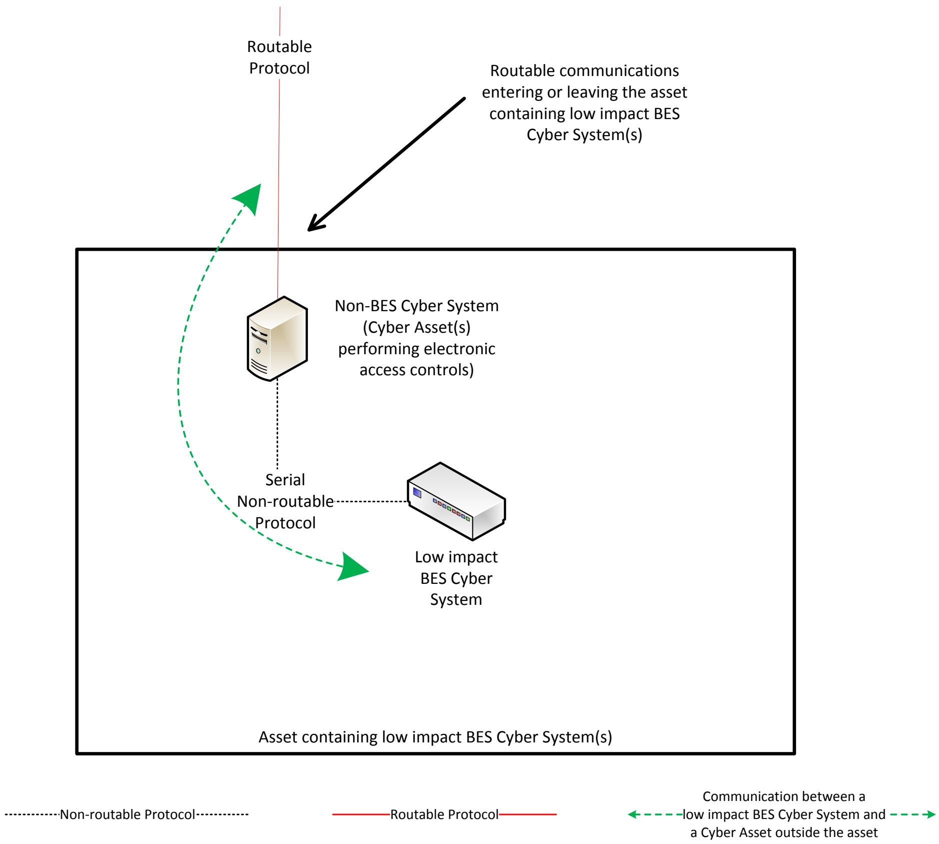
The Responsible Entity may choose to utilize a uni-directional gateway as the electronic access control. The low impact BES Cyber System(s) is not accessible (data cannot flow into the low impact BES Cyber System) using the routable protocol entering the asset due to the implementation of a “one-way” (uni-directional) path for data to flow. The uni-directional gateway is configured to permit only the necessary outbound communications using the routable protocol communication leaving the asset.



Reference Model 4

Reference Model 5 – User Authentication

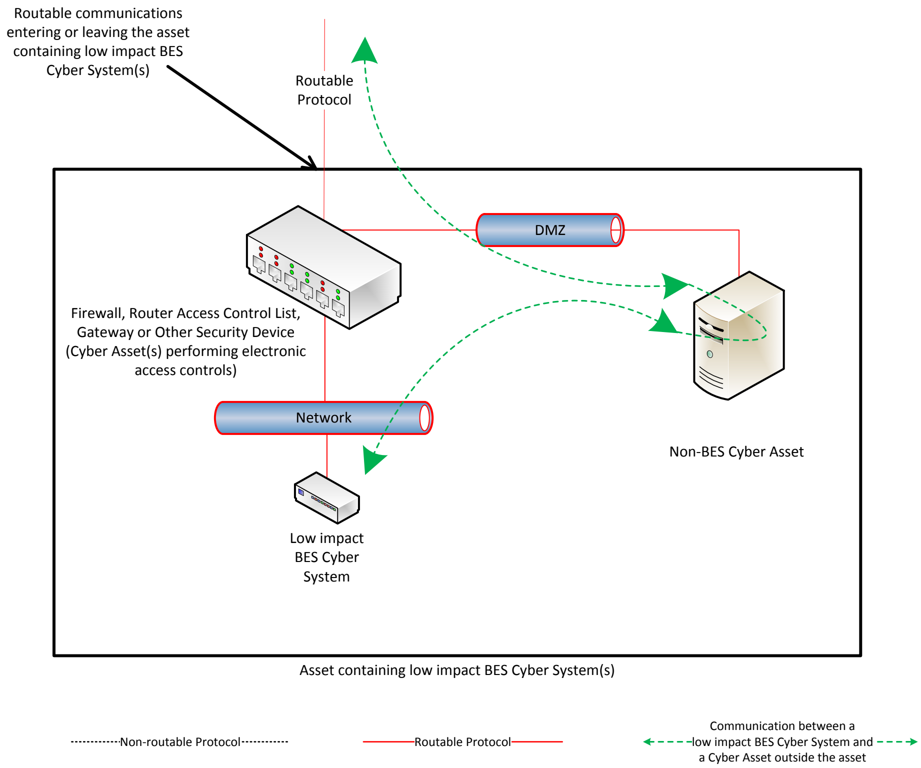
This reference model demonstrates that Responsible Entities have flexibility in choosing electronic access controls so long as the security objective of the requirement is met. The Responsible Entity may choose to utilize a non-BES Cyber Asset located at the asset containing the low impact BES Cyber System that requires authentication for communication from the Cyber Asset(s) outside the asset. This non-BES Cyber System performing the authentication permits only authenticated communication to connect to the low impact BES Cyber System(s), meeting the first half of the security objective to permit only necessary inbound electronic access. Additionally, the non-BES Cyber System performing authentication is configured such that it permits only necessary outbound communication meeting the second half of the security objective. Often, the outbound communications would be controlled in this network architecture by permitting no communication to be initiated from the low impact BES Cyber System. This configuration may be beneficial when the only communication to a device is for user-initiated interactive access.



Reference Model 5

Reference Model 6 – Indirect Access

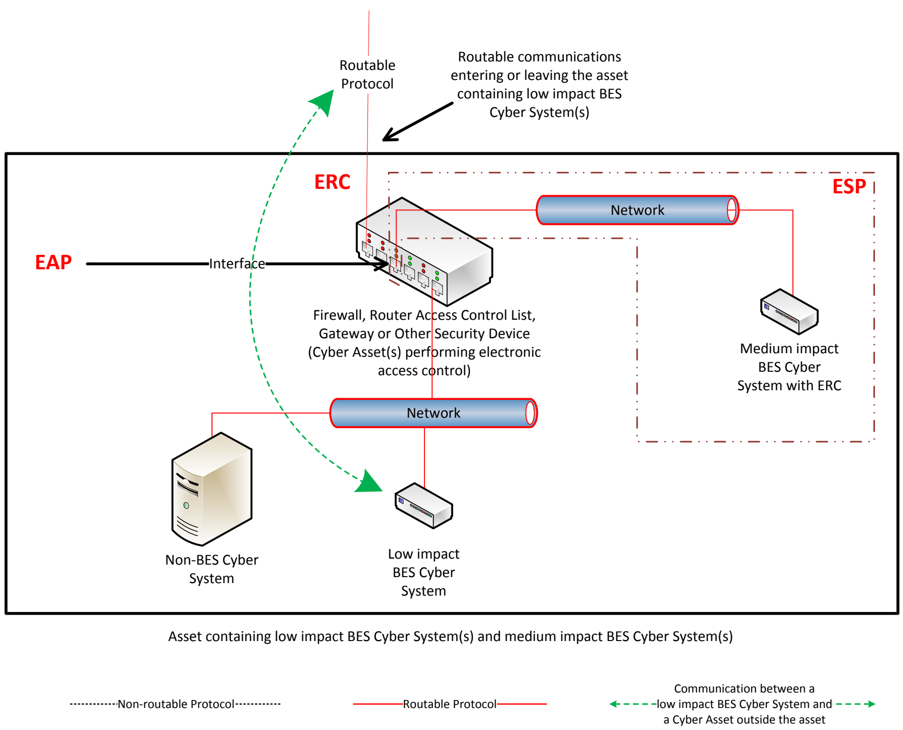
In implementing its electronic access controls, the Responsible Entity may identify that it has indirect access between the low impact BES Cyber System and a Cyber Asset outside the asset containing the low impact BES Cyber System through a non-BES Cyber Asset located within the asset. This indirect access meets the criteria of having communication between the low impact BES Cyber System and a Cyber Asset outside the asset containing the low impact BES Cyber System. In this reference model, it is intended that the Responsible Entity implement electronic access controls that permit only necessary inbound and outbound electronic access to the low impact BES Cyber System. Consistent with the other reference models provided, the electronic access in this reference model is controlled using the security device that is restricting the communication that is entering or leaving the asset.



Reference Model 6

Reference Model 7 – Electronic Access Controls at assets containing low impact BES Cyber Systems and ERC

In this reference model, there is both a routable protocol entering and leaving the asset containing the low impact BES Cyber System(s) that is used by Cyber Asset(s) outside the asset and External Routable Connectivity because there is at least one medium impact BES Cyber System and one low impact BES Cyber System within the asset using the routable protocol communications. The Responsible Entity may choose to leverage an interface on the medium impact Electronic Access Control or Monitoring Systems (EACMS) to provide electronic access controls for purposes of CIP-003. The EACMS is therefore performing multiple functions – as a medium impact EACMS and as implementing electronic access controls for an asset containing low impact BES Cyber Systems.

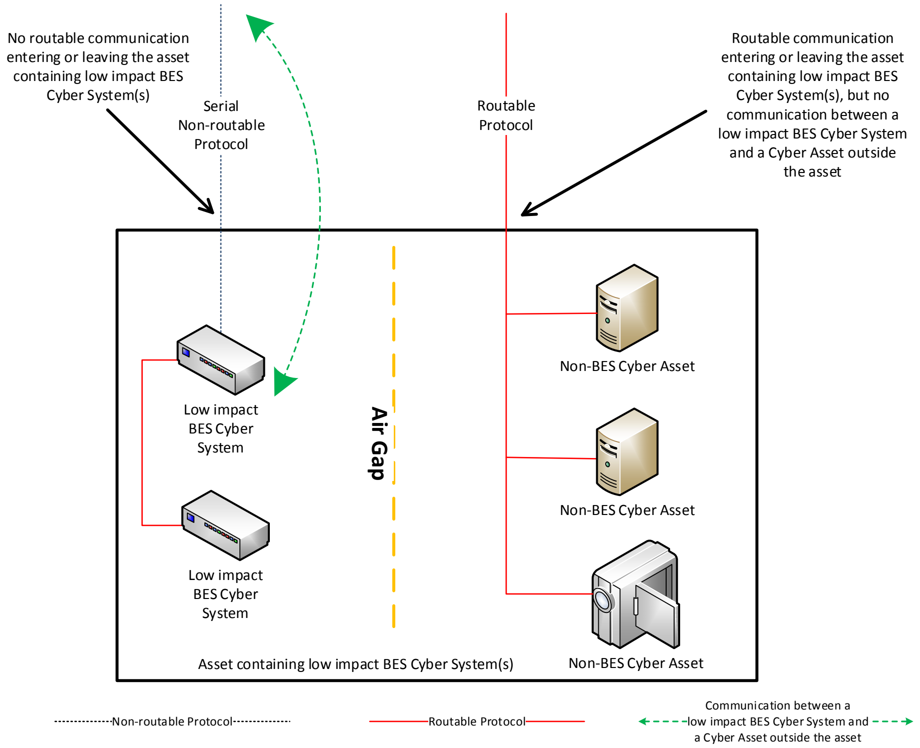


Reference Model 7

Reference Model 8 – Physical Isolation and Serial Non-routable Communications – No Electronic Access Controls Required

In this reference model, the criteria from Attachment 1, Section 3.1 requiring the implementation of electronic access controls are not met. This reference model demonstrates three concepts:

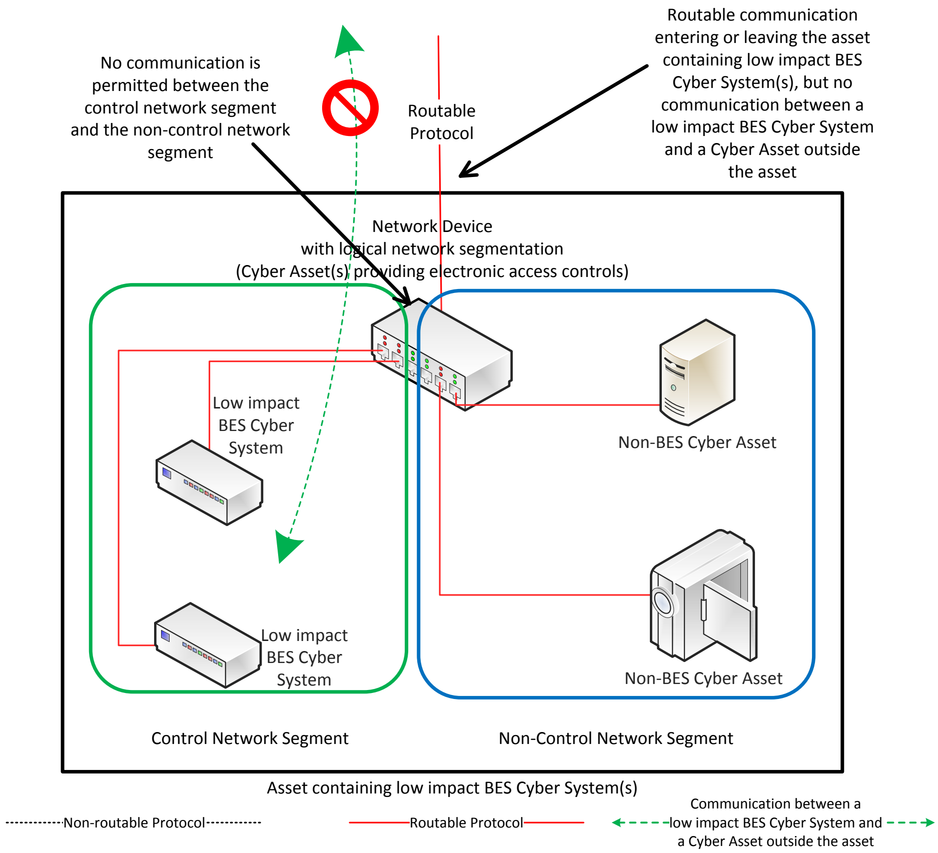
1) The physical isolation of the low impact BES Cyber System(s) from the routable protocol communication entering or leaving the asset containing the low impact BES Cyber System(s), commonly referred to as an 'air gap', mitigates the need to implement the required electronic access controls;
2) The communication to the low impact BES Cyber System from a Cyber Asset outside the asset containing the low impact BES Cyber System(s) using only a serial non-routable protocol where such communication is entering or leaving the asset mitigates the need to implement the required electronic access controls.
3) The routable protocol communication between the low impact BES Cyber System(s) and other Cyber Asset(s), such as the second low impact BES Cyber System depicted, may exist without needing to implement the required electronic access controls so long as the routable protocol communications never leaves the asset containing the low impact BES Cyber System(s).



Reference Model 8

Reference Model 9 – Logical Isolation - No Electronic Access Controls Required

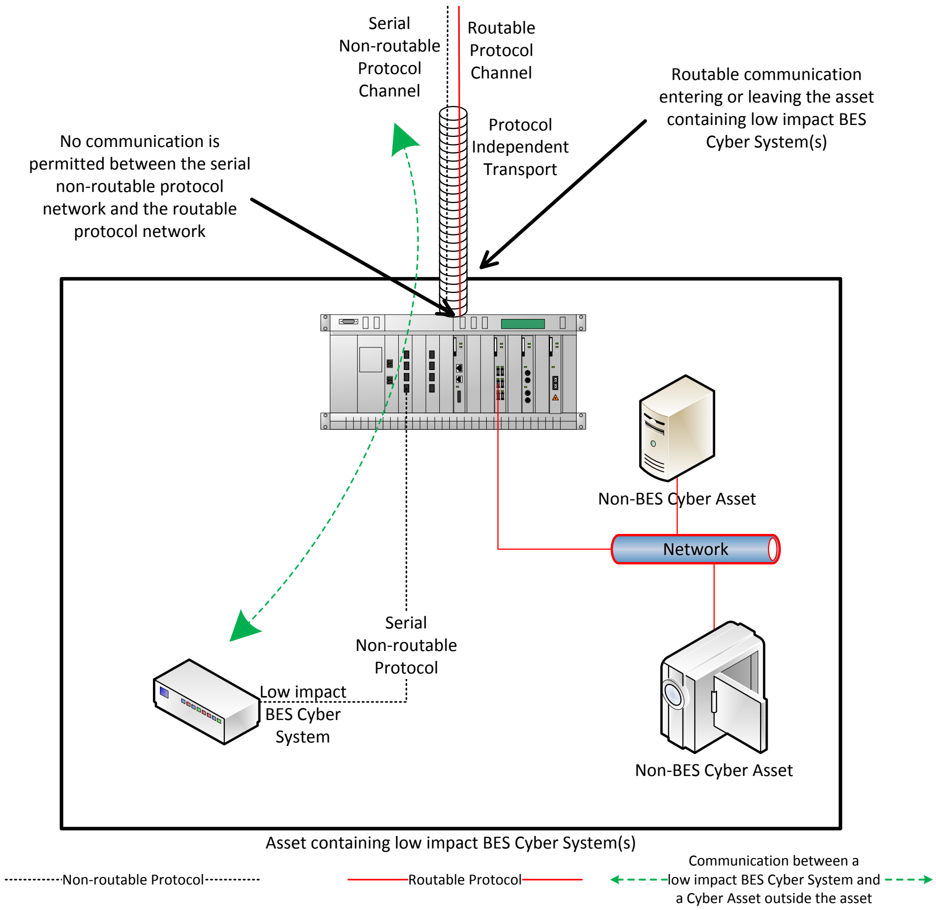
In this reference model, the criteria from Attachment 1, Section 3.1 requiring the implementation of electronic access controls are not met. The Responsible Entity has logically isolated the low impact BES Cyber System(s) from the routable protocol communication entering or leaving the asset containing low impact BES Cyber System(s). The logical network segmentation in this reference model permits no communication between a low impact BES Cyber System and a Cyber Asset outside the asset. Additionally, no indirect access exists because those non-BES Cyber Assets that are able to communicate outside the asset are strictly prohibited from communicating to the low impact BES Cyber System(s). The low impact BES Cyber System(s) is on an isolated network segment with logical controls preventing routable protocol communication into or out of the network containing the low impact BES Cyber System(s) and these communications never leave the asset using a routable protocol.



Reference Model 9

Reference Model 10 - Serial Non-routable Communications Traversing an Isolated Channel on a Non-routable Transport Network – No Electronic Access Controls Required

In this reference model, the criteria from Attachment 1, Section 3.1 requiring the implementation of electronic access controls are not met. This reference model depicts communication between a low impact BES Cyber System and a Cyber Asset outside the asset containing the low impact BES Cyber System over a serial non-routable protocol which is transported across a wide-area network using a protocol independent transport that may carry routable and non-routable communication such as a Time-Division Multiplexing (TDM) network, a Synchronous Optical Network (SONET), or a Multiprotocol Label Switching (MPLS) network. While there is routable protocol communication entering or leaving the asset containing low impact BES Cyber Systems(s) and there is communication between a low impact BES Cyber System and a Cyber Asset outside the asset, the communication between the low impact BES Cyber System and the Cyber Asset outside the asset is not using the routable protocol communication. This model is related to Reference Model 9 in that it relies on logical isolation to prohibit the communication between a low impact BES Cyber System and a Cyber Asset outside the asset from using a routable protocol.



Reference Model 10

Dial-up Connectivity

Dial-up Connectivity to a low impact BES Cyber System is set to dial out only (no auto-answer) to a preprogrammed number to deliver data. Incoming Dial-up Connectivity is to a dialback modem, a modem that must be remotely controlled by the control center or control room, has some form of access control, or the low impact BES Cyber System has access control.

Insufficient Access Controls

Some examples of situations that would lack sufficient access controls to meet the intent of this requirement include:

- An asset has Dial-up Connectivity and a low impact BES Cyber System is reachable via an auto-answer modem that connects any caller to the Cyber Asset that has a default password. There is no practical access control in this instance.
- A low impact BES Cyber System has a wireless card on a public carrier that allows the BES Cyber System to be reachable via a public IP address. In essence, low impact BES Cyber Systems should not be accessible from the Internet and search engines such as Shodan.
- Dual-homing or multiple-network interface cards without disabling IP forwarding in the non-BES Cyber Asset within the DMZ to provide separation between the low impact BES Cyber System(s) and the external network would not meet the intent of “controlling” inbound and outbound electronic access assuming there was no other host-based firewall or other security devices on the non-BES Cyber Asset.

Requirement R2, Attachment 1, Section 4 – Cyber Security Incident Response

The entity should have one or more documented Cyber Security Incident response plan(s) that include each of the topics listed in Section 4. If, in the normal course of business, suspicious activities are noted at an asset containing low impact BES Cyber System(s), the intent is for the entity to implement a Cyber Security Incident response plan that will guide the entity in responding to the incident and reporting the incident if it rises to the level of a Reportable Cyber Security Incident.

Entities are provided the flexibility to develop their Attachment 1, Section 4 Cyber Security Incident response plan(s) by asset or group of assets. The plans do not need to be on a per asset site or per low impact BES Cyber System basis. Entities can choose to use a single enterprise-wide plan to fulfill the obligations for low impact BES Cyber Systems.

The plan(s) must be tested once every 36 months. This is not an exercise per low impact BES Cyber Asset or per type of BES Cyber Asset but rather is an exercise of each incident response plan the entity created to meet this requirement. An actual Reportable Cyber Security Incident counts as an exercise as do other forms of tabletop exercises or drills. NERC-led exercises such as GridEx participation would also count as an exercise provided the entity’s response plan is followed. The intent of the requirement is for entities to keep the Cyber Security Incident response plan(s) current, which includes updating the plan(s), if needed, within 180 days following a test or an actual incident.

For low impact BES Cyber Systems, the only portion of the definition of Cyber Security Incident that would apply is, “A malicious act or suspicious event that disrupts, or was an attempt to disrupt, the operation of a BES Cyber System." The other portion of that definition is not to be used to require ESPs and PSPs for low impact BES Cyber Systems.

Requirement R2, Attachment 1, Section 5 – Transient Cyber Assets and Removable Media Malicious Code Risk Mitigation

Most BES Cyber Assets and BES Cyber Systems are isolated from external public or untrusted networks, and therefore ~~Responsible Entiteis need~~ Transient Cyber Assets and Removable Media are needed to transport files to and from secure areas to maintain, monitor, or troubleshoot critical systems. Transient Cyber Assets and Removable Media are a potential means for cyber-attack. To protect the BES Cyber Assets and BES Cyber Systems, CIP-003 Requirement R2, Attachment 1, Section 5 requires Responsible Entities to document and implement a plan for how they will mitigate the risk of malicious code introduction to low impact BES Cyber Systems from Transient Cyber Assets and Removable Media. The approach of defining a plan allows the Responsible Entity to document processes that are supportable within its organization and in alignment with its change management processes.

Transient Cyber Assets can be one of many types of devices~~, including~~ from a specially-designed device~~s~~ for maintaining equipment in support of the BES ~~or~~to a platform such as a laptop, desktop, or tablet that may interface with or run applications that support BES Cyber Systems and is capable of transmitting executable code to the BES Cyber Asset(s) or BES Cyber System(s). Note: Cyber Assets connected to a BES Cyber System for less than 30 days due to an unplanned removal, such as premature failure, are not intended to be identified as Transient Cyber Assets. Removable Media subject to this requirement include, among others, floppy disks, compact disks, USB flash drives, external hard drives, and other flash memory cards/drives that contain nonvolatile memory.

Examples of these temporarily connected devices include, but are not limited to:

- Diagnostic test equipment;
- Equipment used for BES Cyber System maintenance; or
- Equipment used for BES Cyber System configuration.

To meet the objective of mitigating risks associated with the introduction of malicious code at low impact BES Cyber Systems, Section 5 specifies the capabilities and possible security methods available to Responsible Entities based upon asset type and ownership.

With the list of options provided in Attachment 1, the entity has the discretion to use the option(s) that is most appropriate. This includes documenting its approach for how and when the entity reviews the Transient Cyber Asset under its control or under the control of parties other than the Responsible Entity. The entity should avoid implementing a security function that jeopardizes reliability by taking actions that would negatively impact the performance or support of the Transient Cyber Asset or BES Cyber Asset.

~~Vulnerability~~Malicious Code Risk Mitigation
The terms "mitigate", "mitigating", and "mitigation" are used in ~~the sections~~Section 5 in Attachment 1 to address the risks posed by malicious code when connecting Transient Cyber Assets and Removable Media to BES Cyber Systems. ~~Mitigation in this context does not necessarily require that each vulnerability be individually addressed or remediated, as many vulnerabilities may be unknown or not have an impact on the system to which the Transient Cyber Asset or Removable Media is connected.~~ Mitigation is intended to mean that entities ~~take steps to~~ reduce security risks presented by connecting the Transient Cyber Asset or Removable Media. When determining the method(s) to mitigate the introduction of malicious code, it is not intended for entities to perform and document a formal risk assessment associated with the introduction of malicious code.

Per Transient Cyber Asset Capability
As with other CIP standards, the requirements are intended for an entity to use the method(s) that the system is capable of performing. The use of "per Transient Cyber Asset capability" is to eliminate the need for a Technical Feasibility Exception when it is understood that the device cannot use a method(s). For example, for malicious code, many types of appliances are not capable of implementing antivirus software; therefore, because it is not a capability of those types of devices, implementation of the antivirus software would not be required for those devices.

Requirement R2, Attachment 1, Section 5.1 - Transient Cyber Asset(s) Managed by the Responsible Entity

For Transient Cyber Assets and Removable Media that are connected to both low impact and medium/high impact BES Cyber Systems, entities must be aware of the differing levels of requirements and manage these assets under the program that matches the highest impact level to which they will connect.

Section 5.1: Entities are to document and implement their ~~process(es~~plan(s) to mitigate malicious code through the use of one or more of the protective measures listed, based on the capability of the Transient Cyber Asset. ~~When addressing malicious code protection, Section 5.1 obligates the Responsible Entities to implement methods to mitigate the introduction of malicious code on Transient Cyber Assets managed by the Responsible Entity.~~

The Responsible Entity has the flexibility to apply the selected method(s) to meet the objective of mitigating the introductions of malicious code either in an on-going or in an on-demand manner. An example of managing a device in an on-going manner is having the antivirus solution for the device managed as part of an end-point security solution with current signature or pattern updates, regularly scheduled systems scans, etc. In contrast, for devices that are used infrequently and the signatures or patterns are not kept current, the entity may manage those devices in an on-demand manner by requiring an update to the signatures or patterns and a scan of the device before the device is connected to ensure that it is free of malicious code.

Selecting management in an on-going or on-demand manner is not intended to imply that the control has to be verified at every single connection. For example, if the device is managed in an on-demand manner, but will be used to perform maintenance on several BES Cyber Asset(s), the Responsible Entity may choose to document that the Transient Cyber Asset has been updated before being connected as a Transient Cyber Asset for the first use of that maintenance work. The intent is not to require a log documenting each connection of a Transient Cyber Asset to a BES Cyber Asset.

~~Selecting management in an on-going or on-demand manner is not intended to imply that the control has to be verified at every single connection. For example, if the device is managed in an on-demand manner, but will be used to perform maintenance on several BES Cyber Asset(s), the Responsible Entity may choose to document that the Transient Cyber Asset has been updated before being connected as a Transient Cyber Asset for the first use of that maintenance work. The intent is not to require a log documenting each connection of a Transient Cyber Asset to a BES Cyber Asset.~~

The following is ~~some~~ additional discussion of the methods to mitigate the introduction of malicious code.

- Antivirus software, including manual or managed updates of signatures or patterns, provides flexibility to manage Transient Cyber Asset(s) by deploying antivirus or endpoint security tools that maintain a scheduled update of the signatures or patterns. Also, for devices that do not regularly connect to receive scheduled updates, entities may choose to update the signatures or patterns and scan the Transient Cyber Asset prior to connection to ensure no malicious software is present.
- Application whitelisting is a method of authorizing only the applications and processes that are necessary on the Transient Cyber Asset. This reduces the risk that malicious software could execute on the Transient Cyber Asset and impact the BES Cyber Asset or BES Cyber System.
- ~~If a Responsible Entity chooses touse~~ When using methods ~~that mitigate the introduction of malicious code~~ other than those listed, ~~it should documentat~~entities need to document how the other method(s) meet the ~~mitigation~~objective of mitigating the risk of the introduction of malicious code ~~objective~~.

If malicious code is discovered on the Transient Cyber Asset, it must be mitigated prior to connection to a BES Cyber System to prevent ~~it~~the malicious code from being introduced into the BES Cyber ~~Asset or~~ System. ~~Alternatively, if malicious code is discovered, a~~An entity may choose to not connect the Transient Cyber Asset to a BES Cyber System to prevent the malicious code from being introduced into the BES Cyber System. Entities should also consider whether the detected malicious code is a Cyber Security Incident.

Requirement R2, Attachment 1, Section 5.2 - Transient Cyber Asset(s) Managed by a Party Other than the Responsible Entity

Section 5 also recognizes the lack of direct control over Transient Cyber Assets that are managed by parties other than the Responsible Entity. This lack of control, however, does not obviate the Responsible Entity's responsibility to ensure that methods have been deployed to mitigate the introduction of malicious code to low impact BES Cyber System(s) from Transient Cyber Assets it does not manage. Section 5 requires entities to review the other party's security practices with respect to Transient Cyber Assets to help meet the objective of the requirement. The use of "prior to connecting the Transient Cyber Assets" is intended to ensure that the Responsible Entity conducts the review before the first connection of the Transient Cyber Asset to help meet the objective to mitigate the introduction of malicious code. ~~is t~~The SDT does not intend for the Responsible Entity to conduct a review for every single connection of that Transient Cyber Asset once the Responsible Entity has established the Transient Cyber Asset is meeting the security objective. The intent is ~~also~~ to not ~~to~~ require a log documenting each connection of a Transient Cyber Asset to a BES Cyber Asset.

To facilitate these controls, Responsible Entities may execute agreements with other parties to provide support services to BES Cyber Systems and BES Cyber Assets that may involve the use of Transient Cyber Assets. Entities may consider using the Department of Energy Cybersecurity Procurement Language for Energy Delivery dated April 2014.[1] Procurement language may unify the other party~~'s~~ and entity~~'s~~ actions supporting the BES Cyber Systems and BES Cyber Assets. CIP program attributes may be considered including roles and responsibilities, access controls, monitoring, logging, vulnerability, and patch management along with incident response and back up recovery may be part of the other party's support. Entities ~~should~~may consider the "General Cybersecurity Procurement Language" and "The Supplier's Life Cycle Security Program" when drafting Master Service Agreements, Contracts, and the CIP program processes and controls.

Section 5.2: Entities are to document and implement their process(es) to mitigate the introduction of malicious code through the use of one or more of the protective measures listed.

- Review the use of antivirus software and signature or pattern levels to ensure that the level is adequate to the Responsible Entity to mitigate the risk of malicious software being introduced to an applicable system.
- Review the antivirus or endpoint security processes of the other party to ensure that their processes are adequate to the Responsible Entity to mitigate the risk of introducing malicious software to an applicable system.
- Review the use of application whitelisting used by the other party to mitigate the risk of introducing malicious software to an applicable system.
- Review the use of live operating systems or software executable only from read-only media to ensure that the media is free from malicious software itself. Entities should review the processes to build the read-only media as well as the media itself.
- Review system hardening practices used by the other party to ensure that unnecessary ports, services, applications, etc. have been disabled or removed. This methodasure

[1] http://www.energy.gov/oe/downloads/cybersecurity-procurement-language-energy-delivery-april-2014

~~helps~~ intends to reduce the attack surface on the Transient Cyber Asset and reduce the avenues by which malicious software could be introduced.

Requirement R2, Attachment 1, Section 5.3 - Removable Media

Entities have a high level of control for Removable Media that are going to be connected to their BES Cyber Assets.

Section 5.3: Entities are to document and implement their process(es) to mitigate the introduction of malicious code through the use of one or more method(s) to detect malicious code on the Removable Media before it is connected to a BES Cyber Asset. When using the method(s) to detect malicious code, it is expected to occur from a system that is not part of the BES Cyber System to reduce the risk of propagating malicious code into the BES Cyber System network or onto one of the BES Cyber Assets. If malicious code is discovered, it must be removed or mitigated to prevent it from being introduced into the BES Cyber Asset or BES Cyber System. Entities should also consider whether the detected malicious code is a Cyber Security Incident. Frequency and timing of the methods used to detect malicious code were intentionally excluded from the requirement because there are multiple timing scenarios that can be incorporated into a plan to mitigate the risk of malicious code. ~~However, t~~The SDT does not intend to obligate ~~for~~ a Responsible Entity to conduct a review for every single connection of ~~that~~ Removable Media, but rather to implement ~~their~~ its plan~~rocess~~(~~e~~s) in a manner that protects all BES Cyber Systems where ~~the~~ Removable Media may be used. The intent is ~~also~~ to not ~~to~~ require a log documenting each connection of Removable Media to a BES Cyber Asset.

As a method to detect malicious code, entities may choose to use Removable Media with on-board malicious code detection tools. For these tools, the Removable Media are still used in conjunction with a Cyber Asset to perform the detection. For Section 5.3.1, the Cyber Asset used to perform the malicious code detection must be outside of the BES Cyber System.

Requirement R3:

The intent of CIP-003-7, Requirement R3 is effectively unchanged since prior versions of the standard. The specific description of the CIP Senior Manager has now been included as a defined term rather than clarified in the Reliability Standard itself to prevent any unnecessary cross-reference to this standard. It is expected that the CIP Senior Manager will play a key role in ensuring proper strategic planning, executive/board-level awareness, and overall program governance.

Requirement R4:

As indicated in the rationale for CIP-003-7, Requirement R4, this requirement is intended to demonstrate a clear line of authority and ownership for security matters. The intent of the SDT was not to impose any particular organizational structure, but, rather, the intent is to afford the Responsible Entity significant flexibility to adapt this requirement to its existing organizational structure. A Responsible Entity may satisfy this requirement through a single delegation document or through multiple delegation documents. The Responsible Entity can make use of the delegation of the delegation authority itself to increase the flexibility in how this applies to its organization. In such a case, delegations may exist in numerous documentation records as long as the collection of these documentation records shows a clear line of authority back to the CIP Senior Manager. In addition, the CIP Senior Manager could also choose not to delegate any authority and meet this requirement without such delegation documentation.

The Responsible Entity must keep its documentation of the CIP Senior Manager and any delegations up-to-date. This is to ensure that individuals do not assume any undocumented authority. However, delegations do not have to be re-instated if the individual who delegated the task changes roles or the individual is replaced. For instance, assume that John Doe is named the CIP Senior Manager and he delegates a specific task to the Substation Maintenance Manager. If John Doe is replaced as the CIP Senior Manager, the CIP Senior Manager documentation must be updated within the specified timeframe, but the existing delegation to the Substation Maintenance Manager remains in effect as approved by the previous CIP Senior Manager, John Doe.

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 Requirement R1:

One or more security policies enable effective implementation of the requirements of the cyber security Reliability Standards. The purpose of policies is to provide a management and governance foundation for all requirements that apply to a Responsible Entity's BES Cyber Systems. The Responsible Entity can demonstrate through its policies that its management supports the accountability and responsibility necessary for effective implementation of the requirements.

Annual review and approval of the cyber security policies ensures that the policies are kept-up-to-date and periodically reaffirms management's commitment to the protection of its BES Cyber Systems.

Rationale for Requirement R2:

In response to FERC Order No. 791, Requirement R2 requires entities to develop and implement cyber security plans to meet specific security control objectives for assets containing low impact BES Cyber System(s). The cyber security plan(s) covers five subject matter areas: (1) cyber security awareness; (2) physical security controls; (3) electronic access controls; (4) Cyber Security Incident response; and (5) Transient Cyber Asset and Removable Media Malicious Code Risk Mitigation. This plan(s), along with the cyber security policies required under Requirement R1, Part 1.2, provides a framework for operational, procedural, and technical safeguards for low impact BES Cyber Systems.

Considering the varied types of low impact BES Cyber Systems across the BES, Attachment 1 provides Responsible Entities flexibility on how to apply the security controls to meet the security objectives. Additionally, because many Responsible Entities have multiple-impact rated BES Cyber Systems, nothing in the requirement prohibits entities from using their high and medium impact BES Cyber System policies, procedures, and processes to implement security controls required for low impact BES Cyber Systems, as detailed in Requirement R2, Attachment 1.

Responsible Entities will use their identified assets containing low impact BES Cyber System(s) (developed pursuant to CIP-002) to substantiate the sites or locations associated with low impact BES Cyber System(s). However, there is no requirement or compliance expectation for Responsible Entities to maintain a list(s) of individual low impact BES Cyber System(s) and their associated cyber assets or to maintain a list of authorized users.

Rationale for Requirement R3:

The identification and documentation of the single CIP Senior Manager ensures that there is clear authority and ownership for the CIP program within an organization, as called for in Blackout Report Recommendation 43. The language that identifies CIP Senior Manager responsibilities is included in the Glossary of Terms used in NERC Reliability Standards so that it may be used across the body of CIP standards without an explicit cross-reference.

FERC Order No. 706, Paragraph 296, requests consideration of whether the single senior manager should be a corporate officer or equivalent. As implicated through the defined term, the senior manager has "the overall authority and responsibility for leading and managing implementation of the requirements within this set of standards" which ensures that the senior manager is of sufficient position in the Responsible Entity to ensure that cyber security receives the prominence that is necessary. In addition, given the range of business models for responsible entities, from municipal, cooperative, federal agencies, investor owned utilities, privately owned utilities, and everything in between, the SDT believes that requiring the CIP Senior Manager to be a "corporate officer or equivalent" would be extremely difficult to interpret and enforce on a consistent basis.

Rationale for Requirement R4:

The intent of the requirement is to ensure clear accountability within an organization for certain security matters. It also ensures that delegations are kept up-to-date and that individuals do not assume undocumented authority.

In FERC Order No. 706, Paragraphs 379 and 381, the Commission notes that Recommendation 43 of the 2003 Blackout Report calls for "clear lines of authority and ownership for security matters." With this in mind, the Standard Drafting Team has sought to provide clarity in the requirement for delegations so that this line of authority is clear and apparent from the documented delegations.

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RELIABILITY CORPORATION

Proposed Definitions of: "Transient Cyber Asset" (TCA) and "Removable Media"

Term: "Transient Cyber Asset" (TCA)

Revised Definition:

A Cyber Asset that is:

1. capable of transmitting or transferring executable code,
2. not included in a BES Cyber System,
3. not a Protected Cyber Asset (PCA) associated with high or medium impact BES Cyber Systems, and
4. directly connected (e.g., using Ethernet, serial, Universal Serial Bus, or wireless including near field or Bluetooth communication) for 30 consecutive calendar days or less to a:
   - BES Cyber Asset,
   - network within an Electronic Security Perimeter (ESP) containing high or medium impact BES Cyber Systems, or
   - PCA associated with high or medium impact BES Cyber Systems.

Examples of Transient Cyber Assets include, but are not limited to, Cyber Assets used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.

Redline Definition:

A Cyber Asset that is:

1. capable of transmitting or transferring executable code,
2. not included in a BES Cyber System,
3. not a Protected Cyber Asset (PCA) associated with high or medium impact BES Cyber Systems, and
4. directly connected (e.g., using Ethernet, serial, Universal Serial Bus, or wireless including near field or Bluetooth communication) for 30 consecutive calendar days or less to a:
   - BES Cyber Asset,
   - network within an Electronic Security Perimeter (ESP) containing high or medium impact BES Cyber Systems, or
   - PCA associated with high or medium impact BES Cyber Systems.

Examples of Transient Cyber Assets include, but are not limited to, Cyber Assets used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.

Currently Approved Definition of "Transient Cyber Asset" (TCA):

A Cyber Asset that (i) is capable of transmitting or transferring executable code, (ii) is not included in a BES Cyber System, (iii) is not a Protected Cyber Asset (PCA), and (iv) is directly connected (e.g., using Ethernet, serial, Universal Serial Bus, or wireless, including near field or Bluetooth communication) for 30 consecutive calendar days or less to a BES Cyber Asset, a network within an ESP, or a PCA. Examples include, but are not limited to, Cyber Assets used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.

Term: "Removable Media"

Revised Definition:

Storage media that:

1. are not Cyber Assets,
2. are capable of transferring executable code,
3. can be used to store, copy, move, or access data, and
4. are directly connected for 30 consecutive calendar days or less to a:
   - BES Cyber Asset,
   - network within an Electronic Security Perimeter (ESP) containing high or medium impact BES Cyber Systems, or
   - Protected Cyber Asset associated with high or medium impact BES Cyber Systems.

Examples of Removable Media include, but are not limited to, floppy disks, compact disks, USB flash drives, external hard drives, and other flash memory cards/drives that contain nonvolatile memory.

Redline Definition:

Storage media that:

1. are not Cyber Assets,
2. are capable of transferring executable code,
3. can be used to store, copy, move, or access data, and
4. are directly connected for 30 consecutive calendar days or less to a:
   - BES Cyber Asset, ~~a~~
   - network within an Electronic Security Perimeter (ESP)~~,~~ containing high or medium impact BES Cyber Systems, or ~~a~~
   - Protected Cyber Asset associated with high or medium impact BES Cyber Systems.

Examples of Removable Media include, but are not limited to, floppy disks, compact disks, USB flash drives, external hard drives, and other flash memory cards/drives that contain nonvolatile memory.

Currently Approved Definition of "~~Transient Cyber Asset~~Removable Media"~~ (TCA)~~:

Storage media that (i) are not Cyber Assets, (ii) are capable of transferring executable code, (iii) can be used to store, copy, move, or access data, and (iv) are directly connected for 30 consecutive calendar days or less to a BES Cyber Asset, a network within an ESP, or a Protected Cyber Asset. Examples include, but are not limited to, floppy disks, compact disks, USB flash drives, external hard drives, and other flash memory cards/drives that contain nonvolatile memory.

Implementation Plan

Project 2016-02 Modifications to CIP Standards
Reliability Standard CIP-003-7(i) - Cyber Security – Security Management Controls

Requested Approvals

- Reliability Standard CIP-003-7(i) - Cyber Security – Security Management Controls
- Definition of Transient Cyber Asset (TCA)
- Definition of Removable Media

Requested Retirements

- Reliability Standard CIP-003-6 - Cyber Security – Security Management Control
- Definition Low Impact BES Cyber System Electronic Access Point (LEAP)
- Definition of Low Impact External Routable Connectivity (LERC)
- Definition of Transient Cyber Asset (TCA)
- Definition of Removable Media

Applicable Entities

- Balancing Authority
- Distribution Provider
- Generator Operator
- Generator Owner
- Interchange Coordinator or Interchange Authority
- Reliability Coordinator
- Transmission Operator
- Transmission Owner

Background

On January 21, 2016, the Federal Energy Regulatory Commission (Commission) issued Order No. 822, approving seven Critical Infrastructure Protection (CIP) Reliability Standards and new or modified definitions to be incorporated into the Glossary of Terms Used in NERC Reliability Standards (NERC Glossary). In addition to approving the seven CIP Reliability Standards, the Commission, among other things, directed NERC to: (1) “develop modifications to the CIP Reliability Standards to provide mandatory protection for transient devices used at Low Impact BES Cyber Systems”; and (2) modify the definition of LERC in the NERC Glossary.

With respect to the transient devices directive, the Commission stated:

> 32. After consideration of the comments received on this issue, we conclude that the adoption of controls for transient devices used at Low Impact BES Cyber Systems, including Low Impact Control Centers, will provide an important enhancement to the security posture of the bulk electric system by reinforcing the defense-in-depth nature of the CIP Reliability Standards at all impact levels. Accordingly, we direct that NERC, pursuant to section 215(d)(5) of the FPA, develop modifications to the CIP Reliability Standards to provide mandatory protection for transient devices used at Low Impact BES Cyber Systems based on the risk posed to bulk electric system reliability. While NERC has flexibility in the manner in which it addresses the Commission's concerns, the proposed modifications should be designed to effectively address the risks posed by transient devices to Low Impact BES Cyber Systems in a manner that is consistent with the risk-based approach reflected in the CIP version 5 Standards.

For the LERC directive, the Commission stated:

> 73. Based on the comments received in response to the NOPR, the Commission concludes that a modification to the Low Impact External Routable Connectivity definition to reflect the commentary in the Guidelines and Technical Basis section of CIP-003-6 is necessary to provide needed clarity to the definition and eliminate ambiguity surrounding the term "direct" as it is used in the proposed definition. Therefore, pursuant to section 215(d)(5) of the FPA, we direct NERC to develop a modification to provide the needed clarity, within one year of the effective date of this Final Rule. We agree with NERC and other commenters that a suitable means to address our concern is to modify the Low Impact External Routable Connectivity definition consistent with the commentary in the Guidelines and Technical Basis section of CIP-003-6.

To address these directives, NERC modified Reliability Standard CIP-003. In responding to the transient devices directive, NERC modified the definitions of TCA and Removable Media. The revised definitions ensure the applicability of security controls, provide clarity, and accommodate the use of the terms for all impact levels: high, medium and low. The revised definitions will allow entities to deploy one program to manage TCAs and Removable Media across multiple impact levels.

Further, as an alternative to modifying the LERC definition, the standard drafting team retired the terms "LERC" and "LEAP", incorporating those concepts within the requirement language.

General Considerations

This Implementation Plan does not modify the effective date for CIP-003-6 in the Implementation Plan associated with CIP-003-6 nor any of the phased-in compliance dates included therein except that the compliance dates for CIP-003-6, Requirement R2, Attachment 1, Sections 2 and 3 shall be replaced with the effective date of CIP-003-7(i), provided in this Implementation Plan.

Further, this Implementation Plan clarifies that under Requirement R2 of CIP-003-7(i), the Responsible Entity shall not be required to include in its cyber security plan(s) any elements related to Sections 2, 3, and 5 of Attachment 1 until the effective date of CIP-003-7(i). Upon the effective date of CIP-003-7(i), the Responsible Entity's cyber security plan(s) must include the elements required by Sections 2, 3, and 5 of Attachment 1 and the Responsible Entity must implement the controls included in its plan to meet the objectives of Sections 2, 3, and 5.

Effective Dates

The effective dates for the proposed Reliability Standard and NERC Glossary terms are provided below.

Reliability Standard CIP-003-7(i)

Where approval by an applicable governmental authority is required, Reliability Standard CIP-003-7(i) shall become effective on the first day of the first calendar quarter that is eighteen (18) calendar months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standard CIP-003-7(i) shall become effective on the first day of the first calendar quarter that is eighteen (18) calendar months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

NERC Glossary Definitions of Transient Cyber Asset and Removable Media

Where approval by an applicable governmental authority is required, the definitions of Transient Cyber Asset and Removable Media shall become effective on the first day of the first calendar quarter that is eighteen (18) calendar months after the effective date of the applicable governmental authority's order approving the definitions, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the definitions of Transient Cyber Asset and Removable Media shall become effective on the first day of the first calendar quarter that is eighteen (18) calendar months after the date that the definitions are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Planned or Unplanned Changes

Planned or Unplanned Changes Resulting in a Higher Categorization – This Implementation Plan incorporates by reference the section in the Implementation Plan associated with CIP-003-5 titled Planned or Unplanned Changes Resulting in a Higher Categorization.[1]

Unplanned Changes Resulting in Low Impact Categorization – This Implementation Plan incorporates by reference the section in the Implementation Plan associated with CIP-003-6 titled Unplanned Changes Resulting in Low Impact Categorization. That section provides:

> For unplanned changes resulting in a low impact categorization where previously the asset containing BES Cyber Systems had no categorization, the Responsible Entity shall comply with all Requirements applicable to low impact BES Cyber Systems within 12 calendar months following the identification and categorization of the affected BES Cyber System.

Retirement Date

Reliability Standard CIP-003-6

Reliability Standard CIP-003-6 shall be retired immediately prior to the effective date of Reliability Standard CIP-003-7(i) in the particular jurisdiction in which the revised standard is becoming effective.

Current NERC Glossary of Terms Definition(s) of LERC, LEAP, TCA and Removable Media

The current definitions of LERC and LEAP shall be retired from the NERC Glossary immediately prior to the effective date of Reliability Standard CIP-003-7(i) in the particular jurisdiction in which the revised standard is becoming effective.

The current definitions of Transient Cyber Asset and Removable Media shall be retired from the NERC Glossary immediately prior to the effective date of the revised definitions for those terms in the particular jurisdiction in which the revised definitions are becoming effective.

[1] Due to the length of that section, it is not reproduced herein.

~~A.~~ 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

EOP-004-4 is being posted for a 10-day final ballot period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	07/15/2015
SAR posted for comment	07/21/2015 – 08/19/2015
45-day formal comment period with ballot	07/25/2016 – 09/08/2016
45-day formal comment period with additional ballot	11/18/2016 – 01/09/2016
10-day final ballot period	01/24/2017 – 02/02/2017

Anticipated Actions	Date
NERC Board (Board) adoption	February 2017

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):

None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Event Reporting
2. **Number:** EOP-004-~~3~~4
3. **Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.
4. **Applicability:**

4.1. Functional Entities: For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following ~~functional entities~~Functional Entities will be collectively referred to as "Responsible Entity."

4.1.1. Reliability Coordinator

4.1.2. Balancing Authority

4.1.3. Transmission Owner

4.1.4. Transmission Operator

4.1.5. Generator Owner

4.1.6. Generator Operator

4.1.7. Distribution Provider

~~5.~~ **Effective Date~~s~~:** See the Implementation Plan for ~~the Revised Definition of "Remedial Action Scheme"~~

~~**5. 6. Background:**~~

~~6.~~5. ~~NERC established a SAR Team in 2009 to investigate and propose revisions to the CIP-001 and~~ EOP-004 ~~Reliability Standards. The team was asked to consider the following:~~ -4.

~~1. CIP-001 could be merged with EOP-004 to eliminate redundancies.~~
~~2. Acts of sabotage have to be reported to the DOE as part of EOP-004.~~
~~3. Specific references to the DOE form need to be eliminated.~~
~~4. EOP-004 had some 'fill-in-the-blank' components to eliminate.~~

~~The development included other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient Bulk Electric System reliability standards.~~

~~The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009.~~

~~The DSR SDT developed a concept paper to solicit stakeholder input regarding the proposed reporting concepts that the DSR SDT had developed. The posting of the concept paper sought comments from stakeholders on the "road map" that will be used by the DSR SDT in updating or revising CIP-001 and EOP-004. The concept paper provided stakeholders the background information and thought process of the DSR SDT. The DSR SDT has reviewed the existing standards, the SAR, issues from the NERC issues database and FERC Order 693 Directives in order to determine a prudent course of action with respect to revision of these standards.~~

B. ~~B.~~ Requirements and Measures

R1. ~~R1.~~ Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-~~2-3~~4 Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M1. ~~M1.~~ Each Responsible Entity will have a dated event reporting Operating Plan that includes~~, but is not limited to the~~ protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-~~3~~4 Attachment 1 and in accordance with the entity responsible for reporting.

R2. ~~R2.~~ Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their event reporting Operating Plan ~~within~~by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business day ~~if the event occurs on a weekend (which is recognized to be 4 PM~~(4 p.m. local time ~~on Friday to 8 AM Monday local time).~~will be considered the end of the business day). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M2. ~~M2.~~ Each Responsible Entity will have as evidence of reporting an event~~,~~ to the entities specified per their event reporting Operating Plan either a copy of the completed EOP-004-~~3~~4 Attachment 2 form or a DOE-OE-417 form; and some evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating that the event report was submitted ~~within~~ by the later of 24 hours of recognition of meeting ~~the~~an event type threshold for reporting or by the end of the Responsible Entity's next business day ~~if the event occurs on a weekend (which is recognized to be~~ (4 ~~PM~~p.m. local time ~~on Friday to 8 AM Monday local time). (R2)~~will be considered the end of the business day).

~~**R3.** Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

~~**M3.** Each Responsible Entity will have dated records to show that it validated all contact information contained in the Operating Plan each calendar year. Such evidence may include, but are not limited to, dated voice recordings and operating logs or other communication documentation. (R3)~~

C. ~~C.~~ Compliance

1. ~~1.~~ Compliance Monitoring Process

1.1. ~~1.1~~ Compliance Enforcement Authority:

~~The Regional Entity shall serve as the~~ "Compliance Enforcement Authority ~~(CEA) unless the applicable~~" means NERC or the Regional Entity, or any entity ~~is owned, operated, or controlled~~as otherwise designated by ~~the Regional Entity. In such cases the ERO~~ an Applicable Governmental Authority, in their respective roles of monitoring and/or ~~a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA~~enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. ~~1.2~~ Evidence Retention:

The Responsible 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 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.

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirement~~s~~ R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirement~~s~~ R2~~, R3~~ and Measure M2~~, M3~~.

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 duration 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. ~~1.3~~ Compliance Monitoring and Enforcement ~~Processes:~~Program

~~Compliance Audit~~

~~Self-Certification~~

~~Spot Checking~~

~~Compliance Investigation~~

~~Self-Reporting~~

~~Complaint~~

~~1.4 Additional Compliance Information~~

~~None~~

~~Table of Compliance Elements~~

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 #	2. ~~Time Horizon~~	3. ~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	4. ~~Operations Planning~~	5. ~~Lower~~	The Responsible Entity had an event reporting Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an event reporting Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an ev reporting Opera Plan, but failed include four or applicable even types. OR The Responsible Entity failed to an event report Operating Plan.
R2.	6. ~~Operations Assessment~~	7. ~~Medium~~	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients ~~more than~~up to 24 hours ~~but less than or equal to 36 hours~~ after ~~meeting an event threshold~~the timing requirement	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than ~~36~~24 hours but less than or equal to 48 hours after ~~meeting an event threshold~~the timing	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to ~~60~~72 hours after ~~meeting an event threshold~~the timing	The Responsible Entity submitte event report (e. written or verba all required recipients more ~~60~~72 hours afte ~~meeting an eve threshold~~the tir requirement for ~~reporting~~submi OR

R #	2. ~~Time Horizon~~	3. ~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VS
			for ~~reporting~~submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours~~.~~ or by the end of the next business day, as applicable.	requirement for ~~reporting~~submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours~~.~~ or by the end of the next business day, as applicable.	requirement for ~~reporting~~submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours~~.~~ or by the end of the next business day, as applicable.	The Responsible Entity failed to submit an event report (e.g., wri or verbal) to fou more entities identified in its reporting Opera Plan within 24 h or by the end of next business d applicable. OR The Responsible Entity failed to submit a report an event in EOP 4 Attachment 1

~~8. R3~~	~~9. Operations Planning~~	~~10. Medium~~	~~11. The Responsible Entity validated all contact information contained in the Operating Plan but was late by less than one calendar month.~~ ~~12. OR~~ ~~13. The Responsible Entity validated 75% but less than 100% of the contact information contained in the Operating Plan.~~	~~14. The Responsible Entity validated all contact information contained in the Operating Plan but was late by one calendar month or more but less than two calendar months.~~ ~~15. OR~~ ~~16. The Responsible Entity validated 50% and less than 75% of the contact information contained in the~~	~~17. The Responsible Entity validated all contact information contained in the Operating Plan but was late by two calendar months or more but less than three calendar months.~~ ~~18. OR~~ ~~19. The Responsible Entity validated 25% and less than 50% of the contact information contained in the~~	~~20. The Respo Entity valida all cor inform contai in the Opera Plan b was la three calend month more.~~ ~~21. OR~~ ~~22. The Respo Entity valida less th 25% o contac inform contai in the Opera Plan.~~

R #	2. ~~Time Horizon~~	3. ~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				~~Operating Plan.~~	~~Operating Plan.~~	

~~D.~~

D. Regional Variances

None.

~~E. Interpretations~~

~~None.~~

~~F. References~~

~~Guideline and Technical Basis (attached)~~

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

EOP-004 - Attachment 1: Reportable Events

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written ~~Event Report~~event report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or Voice: 404-446-9780, select Option 1.

Submit EOP-004 Attachment 2 (or DOE-OE-417) pursuant to Requirements R1 and R2.

Rationale for Attachment 1:

System-wide voltage reduction to maintain the continuity of the BES: The TOP is operating the system and is the only entity that would implement system-wide voltage reduction.

Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at a BES control center: To align EOP-004-4 with COM-001-2.1. COM-001-2.1 defined Interpersonal Communication for the NERC Glossary of Terms as: "Any medium that allows two or more individuals to interact, consult, or exchange information." The NERC Glossary of Terms defines Alternative Interpersonal Communication as: "Any Interpersonal Communication that is able to serve as a substitute for, and does not utilize the same infrastructure (medium) as, Interpersonal Communication used for day-to-day operation."

Complete loss of monitoring or control capability at a BES control center: Language revisions to: "Complete loss of monitoring or control capability at a BES control center for 30 continuous minutes or more" provides clarity to the "Threshold for Reporting" and better aligns with the ERO Event Analysis Process.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of a Facility	RC, BA, TOP	Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in ~~actions~~action(s) to avoid a BES Emergency.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of ~~a~~its Facility	~~BA,~~ TO, TOP, GO, GOP, DP	Damage or destruction of its Facility that results from actual or suspected intentional human action. It is not necessary to report theft unless it degrades normal operation of its Facility.
Physical threats to ~~a~~its Facility	~~BA,~~ TO, TOP, GO, GOP, DP	Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at ~~a Facility.~~ ~~Do not report theft unless it degrades normal operation of a~~its Facility.
Physical threats to ~~a~~its BES control center	RC, BA, TOP	Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at ~~a~~its BES control center.
~~BES Emergency requiring public~~Public appeal for load reduction resulting from a BES Emergency	~~Initiating entity is responsible for reporting~~BA	Public appeal for load reduction ~~event~~to maintain continuity of the BES.
~~BES Emergency requiring system~~System-wide voltage reduction resulting from a BES Emergency	~~Initiating entity is responsible for reporting~~TOP	System-wide voltage reduction of 3% or more.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
~~BES Emergency requiring manual firm load shedding~~	~~Initiating entity is responsible for reporting~~	~~Manual firm load shedding ≥ 100 MW.~~
Firm load sheddingresulting from a BES Emergency ~~resulting in automatic firm load shedding~~	~~DP,~~Initiating RC, BA, or TOP	~~Automatic firm~~Firm load shedding ≥ 100 MW (~~via~~manual or automatic ~~undervoltage or underfrequency load shedding schemes, or RAS~~).
~~Voltage~~BES Emergency resulting in voltage deviation on a Facility	TOP	~~Observed within its area a~~A voltage deviation of ~~±~~=/> 10% of nominal voltage sustained for ≥ 15 continuous minutes.
~~IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)~~	~~RC~~	~~Operate outside the IROL for time greater than IROL T_v (all Interconnections) or Operate outside the SOL for more than 30 minutes for Major WECC Transfer Paths (WECC only).~~
~~Loss~~Uncontrolled loss of firm load resulting from a BES Emergency	BA, TOP, DP	~~Loss~~Uncontrolled loss of firm load for ≥ 15 ~~Minutes:~~minutes from a single incident: ≥ 300 MW for entities with previous year's peak demand ≥ 3,000 MW OR ≥ 200 MW for all other entities

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
System separation (islanding)	RC, BA, TOP	Each separation resulting in an island ≥ 100 MW
Generation loss	BA~~, GOP~~	Total generation loss, within one minute, of: ≥ 2,000 MW ~~for entities~~ in the Eastern~~ or~~, Western ~~Interconnection~~ ~~OR~~ ~~≥ 1,000 MW for entities in the ERCOT~~ , or Quebec Interconnection OR ≥ 1,400 MW in the ERCOT Interconnection Generation loss will be used to report Forced Outages not weather patterns or fuel supply unavailability for dispersed power producing resources.
Complete loss of off-site power to a nuclear generating plant (grid supply)	TO, TOP	Complete loss of off-site power (LOOP) affecting a nuclear generating station per the Nuclear Plant Interface Requirements
Transmission loss	TOP	Unexpected loss within its area, contrary to design, of three or more BES ~~Elements~~Facilities caused by a common disturbance (excluding successful automatic reclosing).

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Unplanned evacuation of its BES control center ~~evacuation~~	RC, BA, TOP	Unplanned evacuation from its BES control center facility for 30 continuous minutes or more.
Complete loss of ~~voice communication~~Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center	RC, BA, TOP	Complete loss of ~~voice communication~~Interpersonal Communication and Alternative Interpersonal Communication capability affecting ~~a~~its staffed BES control center for 30 continuous minutes or more.
Complete loss of monitoring or control capability at its staffed BES control center	RC, BA, TOP	Complete loss of monitoring or control capability ~~affecting a~~at its staffed BES control center for 30 continuous minutes or more ~~such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable.~~.

EOP-004 - Attachment 2: Event Reporting Form

EOP-004 Attachment 2: Event Reporting Form		
Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net~~,~~ Facsimile 404-446-9770 or voice: 404-446-9780~~., Option 1. Also submit to other applicable organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."~~		
	Task	**Comments**
1.	Entity filing the report include: Company name: Name of contact person: Email address of contact person: Telephone Number: Submitted by (name):	
2.	Date and Time of recognized event. Date: (mm/dd/yyyy) Time: (hh:mm) Time/Zone:	
3.	Did the event originate in your system?	Yes ☐ No☐ Unknown ☐
4.	**Event Identification and Description:**	
	(Check applicable box) ☐ Damage or destruction of a Facility ☐ Physical ~~T~~threat to ~~a~~its Facility ☐ Physical ~~T~~threat to ~~a~~its BES control center ☐ BES Emergency: ☐ firm load shedding ☐ public appeal for load reduction ☐ ~~s~~System-wide voltage reduction ~~☐ manual firm load shedding~~ ~~☐ automatic firm load shedding~~ ~~☐ Voltage~~ ☐ voltage deviation on a Facility ~~☐ IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)~~ ~~☐ Loss~~ ☐ uncontrolled loss of firm load ☐ System separation (islanding) ☐ Generation loss ☐ Complete loss of off-site power to a nuclear generating plant (grid supply) ☐ Transmission loss	Written description (optional):

EOP-004 Attachment 2: Event Reporting Form	
Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net ~~,~~ Facsimile 404-446-9770 or voice: 404-446-9780~~, Option 1. Also submit to other applicable organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."~~	
Task	**Comments**
☐ ~~unplanned~~Unplanned evacuation of its BES control center ~~evacuation~~ ☐ Complete loss of ~~voice communication~~Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center ☐ Complete loss of monitoring or control capability at its staffed BES control center	

Version History

Version	Date	Action	Change Tracking
2		Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting.	Revision to entire standard (Project 2009-01)
2	November 7, 2012	Adopted by the NERC Board of Trustees	
2	June 20, 2013	FERC approved	
3	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special protection System and SPS with Remedial Action Scheme and RAS
3	November 19, 2015	FERC Order issued approving EOP-004-3. Docket No. RM15-13-000.	

Guideline and Technical Basis

~~**Distribution Provider Applicability Discussion**~~

~~The DSR SDT has included Distribution Providers (DP) as an applicable entity under this standard. The team realizes that not all DPs will own BES Facilities and will not meet the "Threshold for Reporting" for any event listed in Attachment 1. These DPs will not have any reports to submit under Requirement R2. However, these DPs will be responsible for meeting Requirements R1 and R3. The DSR SDT does not intend for these entities to have a detailed Operating Plan to address events that are not applicable to them. In this instance, the DSR SDT intends for the DP to have a very simple Operating Plan that includes a statement that there are no applicable events in Attachment 1 (to meet R1) and that the DP will review the list of events in Attachment 1 each year (to meet R3). The team does not think this will be a burden on any entity as the development and annual validation of the Operating Plan should not take more that 30 minutes on an annual basis. If a DP discovers applicable events during the annual review, it is expected that the DP will develop a more detailed Operating Plan to comply with the requirements of the standard.~~

Multiple Reports for a Single Organization

For entities that have multiple registrations, the ~~DSR SDT intends~~requirement is that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.

~~**Summary of Key Concepts**~~

~~The DSR SDT identified the following principles to assist them in developing the standard:~~

- ~~Develop a single form to report disturbances and events that threaten the reliability of the Bulk Electric System~~
- ~~Investigate other opportunities for efficiency, such as development of an electronic form and possible inclusion of regional reporting requirements~~
- ~~Establish clear criteria for reporting~~
- ~~Establish consistent reporting timelines~~
- ~~Provide clarity around who will receive the information and how it will be used~~

~~**23.**~~

~~During the development of concepts, the DSR SDT considered the FERC directive to "further define sabotage". There was concern among stakeholders that a definition may be ambiguous and subject to interpretation. Consequently, the DSR SDT decided to eliminate the term sabotage from the standard. The team felt that it was almost impossible to determine if an act or event was sabotage or vandalism without the intervention of law enforcement. The DSR SDT felt that attempting to define sabotage would result in further ambiguity with respect to reporting events. The term "sabotage" is no longer included in the standard. The events listed in EOP-004 Attachment 1 were developed to provide guidance for reporting both actual events as well as events which may have an impact on the Bulk Electric System. The DSR SDT believes that this is an equally effective and efficient means of addressing the FERC Directive.~~

~~The types of events that are required to be reported are contained within EOP-004 Attachment 1. The DSR SDT has coordinated with the NERC Events Analysis Working Group to develop the list of events that are to be reported under this standard. EOP-004 Attachment 1 pertains to those actions or events that have impacted the Bulk Electric System. These events were previously reported under EOP-004-1, CIP-001-1 or the Department of Energy form OE-417. EOP-004 Attachment 1 covers similar items that may have had an impact on the Bulk Electric System or has the potential to have an impact and should be reported.~~

~~The DSR SDT wishes to make clear that the proposed Standard does not include any real-time operating notifications for the events listed in EOP-004 Attachment 1. Real-time communication is achieved is covered in other standards. The proposed standard deals exclusively with after-the-fact reporting.~~

~~24. Data Gathering~~

~~**25.** The requirements of EOP-004-1 require that entities "promptly analyze Bulk Electric System disturbances on its system or facilities" (Requirement R2). The requirements of EOP-004-3 specify that certain types of events are to be reported but do not include provisions to analyze events. Events reported under EOP-004-3 may trigger further scrutiny by the ERO Events Analysis Program. If warranted, the Events Analysis Program personnel may request that more data for certain events be provided by the reporting entity or other entities that may have experienced the event. Entities are encouraged to become familiar with the Events Analysis Program and the NERC Rules of Procedure to learn more about with the expectations of the program.~~

Law Enforcement Reporting

The reliability objective of EOP-004-~~3~~4 is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.

Stakeholders in the Reporting Process

- Industry
- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC
- DHS – Federal
- Homeland Security- State
- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

~~**Present expectations of the industry under CIP-001-1a**:~~

~~It has been the understanding by industry participants that an occurrence of sabotage has to be reported to the FBI. The FBI has the jurisdictional requirements to investigate acts of sabotage and terrorism. The CIP-001-1-1a standard requires a liaison relationship on behalf of the industry and the FBI or RCMP. These requirements, under the standard, of the industry have not been clear and have led to misunderstandings and confusion in the industry as to how to demonstrate that the liaison is in place and effective. As an example of proof of compliance with Requirement R4, Responsible Entities have asked FBI Office personnel to provide, on FBI letterhead, confirmation of the existence of a working relationship to report acts of sabotage, the number of years the liaison relationship has been in existence, and the validity of the telephone numbers for the FBI.~~

~~**Coordination of Local and State Law Enforcement Agencies with the FBI**~~

~~The Joint Terrorism Task Force (JTTF) came into being with the first task force being established in 1980. JTTFs are small cells of highly trained, locally based, committed investigators, analysts, linguists, SWAT experts, and other specialists from dozens of U.S. law enforcement and intelligence agencies. The JTTF is a multi-agency effort led by the Justice Department and FBI designed to combine the resources of federal, state, and local law enforcement. Coordination and communications largely through the interagency National Joint Terrorism Task Force, working out of FBI Headquarters, which makes sure that information and intelligence flows freely among the local JTTFs. This information flow can be most beneficial to the industry in analytical intelligence, incident response and investigation. Historically, the most immediate response to an industry incident has been local and state law enforcement agencies to suspected vandalism and criminal damages at industry facilities. Relying upon the JTTF coordination between local, state and FBI law enforcement would be beneficial to effective communications and the appropriate level of investigative response.~~

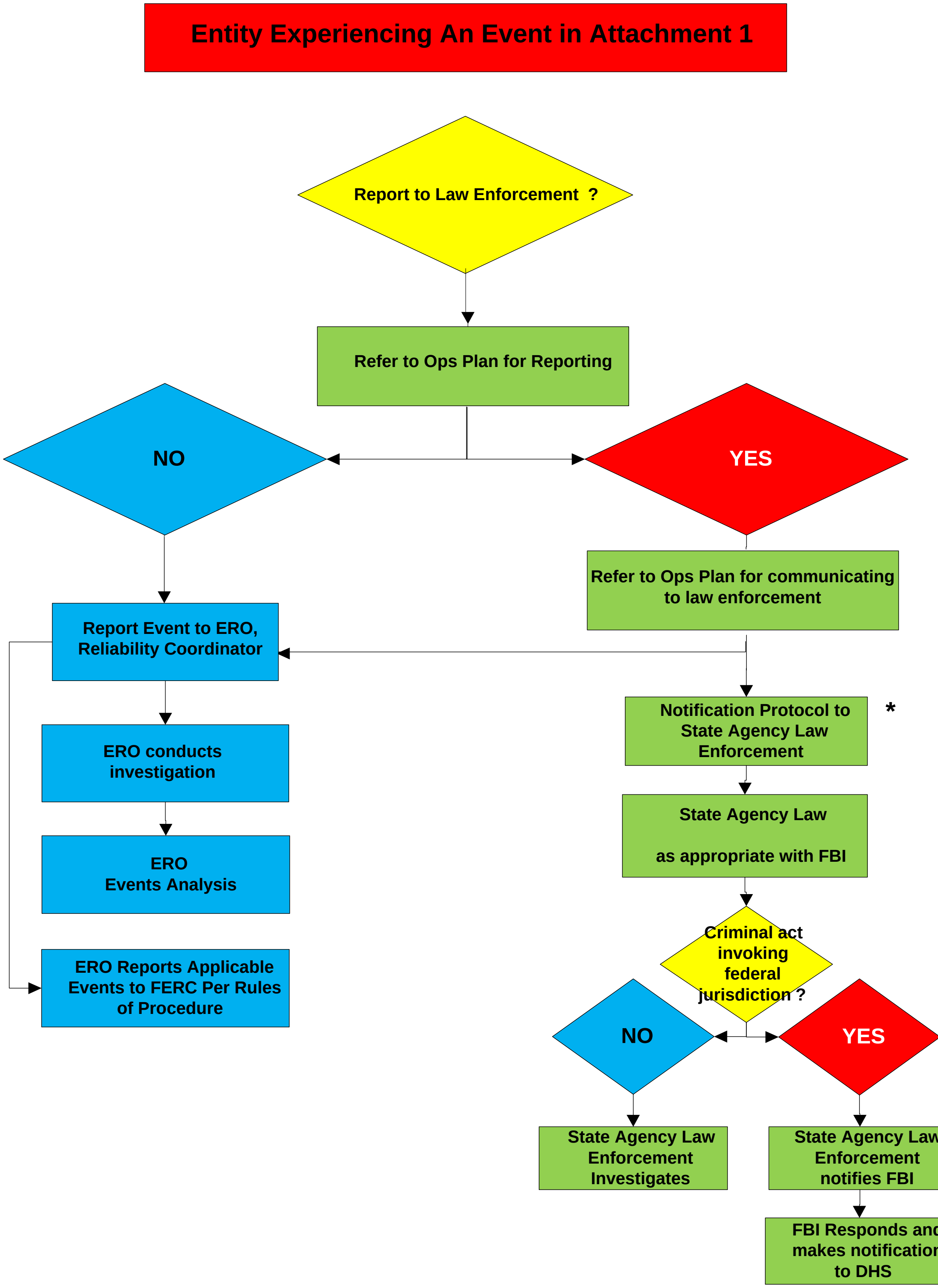
~~Coordination of Local and Provincial Law Enforcement Agencies with the RCMP~~

~~A similar law enforcement coordination hierarchy exists in Canada. Local and Provincial law enforcement coordinate to investigate suspected acts of vandalism and sabotage. The Provincial law enforcement agency has a reporting relationship with the Royal Canadian Mounted Police (RCMP).~~

~~A Reporting Process Solution – EOP-004~~

~~A proposal discussed with the FBI, FERC Staff, NERC Standards Project Coordinator and the SDT Chair is reflected in the flowchart below (Reporting Hierarchy for Reportable Events). Essentially, reporting an event to law enforcement agencies will only require the industry to notify the state or provincial or local level law enforcement agency. The state or provincial or local level law enforcement agency will coordinate with law enforcement with jurisdiction to investigate. If the state or provincial or local level law enforcement agency decides federal agency law enforcement or the RCMP should respond and investigate, the state or provincial or local level law enforcement agency will notify and coordinate with the FBI or the RCMP.~~

Example of Reporting Process including Law Enforcement



* Canadian entities will follow law enforcement protocols applicable in their jurisdictions

~~Disturbance and Sabotage Reporting Standard Drafting Team (Project 2009-01) - Reporting Concepts~~

~~Introduction~~

~~The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009 and has developed updated standards based on the SAR.~~

~~The standards listed under the SAR are:~~

- ~~CIP-001 — Sabotage Reporting~~
- ~~EOP-004 — Disturbance Reporting~~

~~The changes do not include any real-time operating notifications for the types of events covered by CIP-001 and EOP-004. The real-time reporting requirements are achieved through the RCIS and are covered in other standards (e.g. EOP-002-Capacity and Energy Emergencies). These standards deal exclusively with after-the-fact reporting.~~

~~The DSR SDT has consolidated disturbance and sabotage event reporting under a single standard. These two components and other key concepts are discussed in the following sections.~~

~~Summary of Concepts and Assumptions:~~

~~The Standard:~~

- ~~Requires reporting of "events" that impact or may impact the reliability of the Bulk Electric System~~
- ~~Provides clear criteria for reporting~~
- ~~Includes consistent reporting timelines~~
- ~~Identifies appropriate applicability, including a reporting hierarchy in the case of disturbance reporting~~
- ~~Provides clarity around of who will receive the information~~

~~*Discussion of Disturbance Reporting*~~

~~Disturbance reporting requirements existed in the previous version of EOP-004. The current approved definition of Disturbance from the NERC Glossary of Terms is:~~

1. ~~An unplanned event that produces an abnormal system condition.~~
2. ~~Any perturbation to the electric system.~~
3. ~~The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.~~

~~Disturbance reporting requirements and criteria were in the previous EOP-004 standard and its attachments. The DSR SDT discussed the reliability needs for disturbance reporting and developed the list of events that are to be reported under this standard (EOP-004 Attachment 1).~~

~~*Discussion of Event Reporting*~~

~~There are situations worthy of reporting because they have the potential to impact reliability.~~

~~Event reporting facilitates industry awareness, which allows potentially impacted parties to prepare for and possibly mitigate any associated reliability risk. It also provides the raw material, in the case of certain potential reliability threats, to see emerging patterns.~~

~~Examples of such events include:~~

- ~~Bolts removed from transmission line structures~~
- ~~Train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center)~~
- ~~Destruction of Bulk Electric System equipment~~

~~*What about sabotage?*~~

~~One thing became clear in the DSR SDT's discussion concerning sabotage: everyone has a different definition. The current standard CIP-001 elicited the following response from FERC in FERC Order 693, paragraph 471 which states in part: *". . . the Commission directs the ERO to develop the following modifications to the Reliability Standard through the Reliability Standards development process: (1) further define sabotage and provide guidance as to the triggering events that would cause an entity to report a sabotage event."*~~

~~Often, the underlying reason for an event is unknown or cannot be confirmed. The DSR SDT believes that by reporting material risks to the Bulk Electric System using the event categorization in this standard, it will be easier to get the relevant information for mitigation, awareness, and tracking, while removing the distracting element of motivation.~~

~~Certain types of events should be reported to NERC, the Department of Homeland Security (DHS), the Federal Bureau of Investigation (FBI), and/or Provincial or local law enforcement. Other types of events may have different reporting requirements. For example, an event that is related to copper theft may only need to be reported to the local law enforcement authorities.~~

Potential Uses of Reportable Information

~~Event analysis~~General situational awareness, correlation of data, ~~and~~ trend identification, and identification of potential events of interest for further analysis in the ERO Event Analysis Process are a few potential uses for the information reported under this standard. The standard requires Functional ~~e~~Entities to report the incidents and provide ~~known~~ information known at the time of the report. Further data gathering necessary for ~~event~~ analysis is provided for under the ~~Events~~ERO Event Analysis Program and the NERC Rules of Procedure. ~~Other entities (e.g. – NERC, Law Enforcement, etc) will be responsible for performing the analyses.~~ The NERC Rules of Procedure (section 800) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

~~*Collection of Reportable Information or "One stop shopping"*~~

~~The DSR SDT recognizes that some regions require reporting of additional information beyond what is in EOP-004. The DSR SDT has updated the listing of reportable events in EOP-004 Attachment 1 based on discussions with jurisdictional agencies, NERC, Regional Entities and stakeholder input. There is a possibility that regional differences still exist.~~

~~The reporting required by this standard is intended to meet the uses and purposes of NERC. The DSR SDT recognizes that other requirements for reporting exist (e.g., DOE-417 reporting), which may duplicate or overlap the information required by NERC. To the extent that other reporting is required, the DSR SDT envisions that duplicate entry of information should not be necessary, and the submission of the alternate report will be acceptable to NERC so long as all information required by NERC is submitted. For example, if the NERC Report duplicates information from the DOE form, the DOE report may be sent to the NERC in lieu of entering that information on the NERC report.~~

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~~adoption, the text from the rationale text boxes was moved to this section.

~~**Rationale for R1:**~~

~~The requirement to have an Operating Plan for reporting specific types of events provides the entity with a method to have its operating personnel recognize events that affect reliability and to be able to report them to appropriate parties; e.g., Regional Entities, applicable Reliability Coordinators, and law enforcement and other jurisdictional agencies when so recognized. In addition, these event reports are an input to the NERC Events Analysis Program. These other parties use this information to promote reliability, develop a culture of reliability excellence, provide industry collaboration and promote a learning organization.~~

~~Every Registered Entity that owns or operates elements or devices on the grid has a formal or informal process, procedure, or steps it takes to gather information regarding what happened when events occur. This requirement has the Responsible Entity establish documentation on how that procedure, process, or plan is organized. This documentation may be a single document or a combination of various documents that achieve the reliability objective.~~

~~The communication protocol(s) could include a process flowchart, identification of internal and external personnel or entities to be notified, or a list of personnel by name and their associated contact information. An existing procedure that meets the requirements of CIP-001-2a may be included in this Operating Plan along with other processes, procedures or plans to meet this requirement.~~

~~**Rationale for R2:**~~

~~Each Responsible Entity must report and communicate events according to its Operating Plan based on the information in EOP-004-3 Attachment 1. By implementing the event reporting Operating Plan the Responsible Entity will assure situational awareness to the Electric Reliability Organization so that they may develop trends and prepare for a possible next event and mitigate the current event. This will assure that the BES remains secure and stable by mitigation actions that the Responsible Entity has within its function. By communicating events per the Operating Plan, the Responsible Entity will assure that people/agencies are aware of the current situation and they may prepare to mitigate current and further events.~~

~~**Rationale for R3:**~~

~~Requirement 3 calls for the Responsible Entity to validate the contact information contained in the Operating Plan each calendar year. This requirement helps ensure that the event reporting Operating Plan is up to date and entities will be able to effectively report events to assure situational awareness to the Electric Reliability Organization. If an entity experiences an actual event, communication evidence from the event may be used to show compliance with the validation requirement for the specific contacts used for the event.~~

~~**Rationale for EOP-004 Attachment 1:**~~

~~The DSR SDT used the defined term "Facility" to add clarity for several events listed in Attachment 1. A Facility is defined as:~~

> ~~"A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)"~~

~~The DSR SDT does not intend the use of the term Facility to mean a substation or any other facility (not a defined term) that one might consider in everyday discussions regarding the grid. This is intended to mean ONLY a Facility as defined above.~~

~~Version History~~

~~Version~~	~~Date~~	~~Action~~	~~Change Tracking~~
~~2~~		~~Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting.~~	~~Revision to entire standard (Project 2009-01)~~
~~2~~	~~November 7, 2012~~	~~Adopted by the NERC Board of Trustees~~	
~~2~~	~~June 20, 2013~~	~~FERC approved~~	
~~3~~	~~November 13, 2014~~	~~Adopted by the NERC Board of Trustees~~	~~Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS~~
~~3~~	~~November 19, 2015~~	~~FERC Order issued approving EOP-004-3. Docket No. RM15-13-000.~~	

A. Introduction

1. **Title: Transmission System Planning Performance Requirements**

2. **Number: TPL-001-4**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-4:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1
   - P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

- a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.
- b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
   - a. Loss of a tower line with three or more circuits.[11]
   - b. Loss of all Transmission lines on a common Right-of-Way[11].
   - c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   - d. Loss of all generating units at a generating station.
   - e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
   - a. Loss of two generating stations resulting from conditions such as:
     - i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
     - ii. Loss of the use of a large body of water as the cooling source for generation.
     - iii. Wildfires.
     - iv. Severe weather, e.g., hurricanes, tornadoes, etc.
     - v. A successful cyber attack.
     - vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
   - b. Other events based upon operating experience that may result in wide area disturbances.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
   - a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   - b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   - c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   - d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   - e. 3Ø internal breaker fault.
   - f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. 2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. 3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss. 4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service. 5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. 6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground. 7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point. 8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker. 9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. 10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing. 11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less. 12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction. 13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, &

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
67), and tripping (#86, & 94).

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. .The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
    a. The estimated number and type of customers affected

b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community

3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote ‘b’ in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	
4	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in	

		Requirement 1 from Medium to High.	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard TPL-001-4 — Transmission System Planning Performance Requirements

United States

Standard	Requirement	Enforcement Date	Inactive Date
TPL-001-4	R1.	01/01/2015	
TPL-001-4	1.1.	01/01/2015	
TPL-001-4	1.1.1.	01/01/2015	
TPL-001-4	1.1.2.	01/01/2015	
TPL-001-4	1.1.3.	01/01/2015	
TPL-001-4	1.1.4.	01/01/2015	
TPL-001-4	1.1.5.	01/01/2015	
TPL-001-4	1.1.6.	01/01/2015	
TPL-001-4	R2.	01/01/2016	
TPL-001-4	2.1.	01/01/2016	
TPL-001-4	2.1.1.	01/01/2016	
TPL-001-4	2.1.2.	01/01/2016	
TPL-001-4	2.1.3.	01/01/2016	
TPL-001-4	2.1.4.	01/01/2016	
TPL-001-4	2.1.5.	01/01/2016	
TPL-001-4	2.2.	01/01/2016	
TPL-001-4	2.2.1.	01/01/2016	
TPL-001-4	2.3.	01/01/2016	
TPL-001-4	2.4.	01/01/2016	
TPL-001-4	2.4.1.	01/01/2016	
TPL-001-4	2.4.2.	01/01/2016	
TPL-001-4	2.4.3.	01/01/2016	
TPL-001-4	2.5.	01/01/2016	
TPL-001-4	2.6.	01/01/2016	
TPL-001-4	2.6.1.	01/01/2016	
TPL-001-4	2.6.2.	01/01/2016	
TPL-001-4	2.7.	01/01/2016	
TPL-001-4	2.7.1	01/01/2016	
TPL-001-4	2.7.2.	01/01/2016	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard TPL-001-4 — Transmission System Planning Performance Requirements

<u>United States</u>

TPL-001-4	2.7.3.	01/01/2016	
TPL-001-4	2.7.4.	01/01/2016	
TPL-001-4	2.8	01/01/2016	
TPL-001-4	2.8.1.	01/01/2016	
TPL-001-4	2.8.2.	01/01/2016	
TPL-001-4	R3.	01/01/2016	
TPL-001-4	3.1.	01/01/2016	
TPL-001-4	3.2.	01/01/2016	
TPL-001-4	3.3.	01/01/2016	
TPL-001-4	3.3.1.	01/01/2016	
TPL-001-4	3.3.1.1.	01/01/2016	
TPL-001-4	3.3.1.2.	01/01/2016	
TPL-001-4	3.3.2.	01/01/2016	
TPL-001-4	3.4.	01/01/2016	
TPL-001-4	3.4.1.	01/01/2016	
TPL-001-4	3.5.	01/01/2016	
TPL-001-4	R4.	01/01/2016	
TPL-001-4	4.1.	01/01/2016	
TPL-001-4	4.1.1.	01/01/2016	
TPL-001-4	4.1.2.	01/01/2016	
TPL-001-4	4.1.3.	01/01/2016	
TPL-001-4	4.2.	01/01/2016	
TPL-001-4	4.3.	01/01/2016	
TPL-001-4	4.3.1.	01/01/2016	
TPL-001-4	4.3.1.1.	01/01/2016	
TPL-001-4	4.3.1.2.	01/01/2016	
TPL-001-4	4.3.1.3.	01/01/2016	
TPL-001-4	4.3.2.	01/01/2016	
TPL-001-4	4.4.	01/01/2016	
TPL-001-4	4.4.1.	01/01/2016	

* FOR INFORMATIONAL PURPOSES ONLY *

Enforcement Dates: Standard TPL-001-4 — Transmission System Planning Performance Requirements

<u>United States</u>

TPL-001-4	4.5.	01/01/2016	
TPL-001-4	R5.	01/01/2016	
TPL-001-4	R6.	01/01/2016	
TPL-001-4	R7.	01/01/2015	
TPL-001-4	R8.	01/01/2016	
TPL-001-4	8.1.	01/01/2016	

Unofficial Nomination Form

Project 2015-10 Single Points of Failure (TPL-001)

Do not use this form for submitting nominations. Use the electronic form to submit nominations by **8 p.m. Eastern, Friday, August 5, 2016.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form.

Additional information about this project is available on the Project 2015-10 Single Points of Failure (TPL-001) page. If you have questions, contact NERC Standards Developer, Jordan Mallory (via email), or at (404) 446-9733.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls. Previous drafting or review team experience is beneficial, but not required. A brief description of the desired qualifications, expected commitment, and other pertinent information is included below.

Project 2015-10 Single Points of Failure

Modifications have been recommended to Reliability Standard TPL-001-4 based on the following:

Item 1: The System Protection and Control Subcommittee (SPCS) and the System Modeling and Analysis Subcommittee (SAMS) conducted a comprehensive assessment of the study of protection system single points of failure in response to FERC Order No. 754, including analysis of data from the NERC Section 1600 Request for Data or Information. The assessment confirms the existence of a reliability risk associated with single points of failure in protection systems that warrants further action.

Item 2: Further, references to MOD-010 and MOD-012 in Requirement R1 would need to be replaced with MOD-032 due to July 2016 retirement of those standards.

In addition, on October 17, 2013 the Commission issued Order No. 786, which included two directives related to TPL-001-4. The two directives are as follows:

- Paragraph 40 directs NERC to modify Reliability Standard TPL-001-4 to address the concern that the six-month threshold could exclude planned maintenance outages of significant facilities from future planning assessments.
- Paragraph 89 directs NERC to consider a similar spare equipment strategy for stability analysis upon the next review cycle of Reliability Standard TPL-001-4.”

Standard affected: TPL-001-4

The time commitment for these projects is expected to be up to two face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed to meet the agreed-upon timeline the review or drafting team sets forth. Team members may also have side projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the drafting team effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful project outcome.

Name:	
Organization:	
Address:	
Telephone:	
E-mail:	
Please briefly describe your experience and qualifications to serve on the requested Standard Drafting Team (Bio):	
If you are currently a member of any NERC drafting team, please list each team here: ☐ Not currently on any active SAR or standard drafting team. ☐ Currently a member of the following team(s):	
If you previously worked on any NERC drafting team please identify the team(s): ☐ No prior NERC SAR or standard drafting team. ☐ Prior experience on the following team(s):	

Select each NERC Region in which you have experience relevant to the Project for which you are volunteering:		
☐ FRCC	☐ RF	☐ Texas RE
☐ MRO	☐ SERC	☐ WECC
☐ NPCC	☐ SPP RE	☐ NA – Not Applicable

Select each Industry Segment that you represent:	
☐	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, and Provincial Regulatory or other Government Entities
☐	10 — Regional Reliability Organizations and Regional Entities
☐	NA – Not Applicable

Select each Function[1] in which you have current or prior expertise:	
☐ Balancing Authority	☐ Transmission Operator
☐ Compliance Enforcement Authority	☐ Transmission Owner
☐ Distribution Provider	☐ Transmission Planner
☐ Generator Operator	☐ Transmission Service Provider
☐ Generator Owner	☐ Purchasing-selling Entity
☐ Interchange Authority	☐ Reliability Coordinator
☐ Load-serving Entity	☐ Reliability Assurer
☐ Market Operator	☐ Resource Planner
☐ Planning Coordinator	

[1] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:			
Name:		Telephone:	
Organization:		E-mail:	
Name:		Telephone:	
Organization:		E-mail:	

Provide the name and contact information of your immediate supervisor or a member of your management who can confirm your organization’s willingness to support your active participation.			
Name:		Telephone:	
Title:		Email:	

A. Introduction

1. **Title:** **Generator Relay Loadability**

2. **Number:** **PRC-025-1**

   Purpose: To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

3. **Applicability:**

   3.1. Functional Entities:

   3.1.1 Generator Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   3.1.2 Transmission Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   3.1.3 Distribution Provider that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   3.2. Facilities: The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

   3.2.1 Generating unit(s).

   3.2.2 Generator step-up (i.e., GSU) transformer(s).

   3.2.3 Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.[1]

   3.2.4 Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

   3.2.5 Elements utilized in the aggregation of dispersed power producing resources.

4. **Background:**

   After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that

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[1] These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-1 Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

disturbance. This was noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.[2]

During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

5. Effective Date: See Implementation Plan

B. Requirements and Measures

R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-1 – Attachment 1: Relay Settings.

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 (CEA) may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

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[2] Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf)

The Generator Owner, Transmission 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 Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission 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

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 Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with *PRC-025-1 – Attachment 1: Relay Settings*, on an applied load-responsive protective relay.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC System Protection and Control Subcommittee, July 2010, "Power Plant and Transmission System Protection Coordination."

IEEE C37.102-2006, "Guide for AC Generator Protection."

Version History

Version	Date	Action	Change Tracking
1	August 15, 2013	Adopted by NERC Board of Trustees	New
1	July 17, 2014	FERC order issued approving PRC-025-1	

PRC-025-1 – Attachment 1: Relay Settings

Introduction

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in 3.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay pickup setting criteria values are derived from the unit's maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit's nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard.

Asynchronous generator relay pickup setting criteria values (including inverter-based installations) are derived from the site's aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices.

For the application case where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.), the pickup setting criteria shall be determined by vector summing the pickup setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for Special Protection Systems that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of fullload current (e.g., rated armature current), and prevent operation below 115% of full-load current.[3]
7. Protection systems that detect transformer overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.

Table 1

Table 1 beginning on the next page is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant

[3] IEEE C37.102-2006, “Guide for AC Generator Protection,” Section 4.1.1.2.

loads). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive protective relay (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the applied application in the first column. A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word “OR,” and reveals to the reader that the relay for that application has one or more options (i.e., “ways”) to determine the bus voltage and pickup setting criteria in the fourth and fifth column, respectively. The bus voltage column and pickup setting criteria columns provide the criteria for determining an appropriate setting.

The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Synchronous generating unit(s), or Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[4] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Synchronous generating unit(s), or Elements utilized in the aggregation of dispersed power producing resources	Phase time overcurrent relay (51) or (51V-R) – voltage-restrained	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues with a different relay type below			
	Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Asynchronous generating unit(s) (including inverter-based installations), or Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51) or (51V-R) – voltage-restrained	5	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage

A different application starts on the next page

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Generator step-up transformer(s) connected to synchronous generators	Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 14	7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Generator step-up transformer(s) connected to synchronous generators	Phase time overcurrent relay (51) – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 15	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Generator step-up transformer(s) connected to synchronous generators	Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 16	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 17	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51) – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 18	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 19	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
A different application starts below				
Unit auxiliary transformer(s) (UAT)	Phase time overcurrent relay (51) applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip.	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating
		OR		
		13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to synchronous generators	Phase distance relay (21) – directional toward the Transmission system – installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 7	14a	0.85 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		14b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to synchronous generators	Phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or phase time overcurrent relay (51) – installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 8	15a	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		15b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant load. – connected to synchronous generators	Phase directional overcurrent supervisory element (67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer or phase directional time overcurrent relay (67) – directional toward the Transmission system installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 9	16a	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		16b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system– installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 10	17	1.0 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations)	Phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or Phase time overcurrent relay (51) – installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 11	18	1.0 per unit of the line nominal voltage	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Pickup Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations)	Phase directional overcurrent supervisory element (67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer or Phase directional time overcurrent relay (67) – installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 12	19	1.0 per unit of the line nominal voltage	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

PRC-025-1 Guidelines and Technical Basis

Introduction

The document, "Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July 2010.[5]

The basis for the standard's loadability criteria for relays applied at the generator terminals or low-side of the generator step-up (GSU) transformer is the dynamic generating unit loading values observed during the August 14, 2003 blackout, other subsequent system events, and simulations of generating unit response to similar system conditions. The Reactive Power output observed during field-forcing in these events and simulations approaches a value equal to 150 percent of the Real Power (MW) capability of the generating unit when the generator is operating at its Real Power capability. In the SPCS technical reference document, two operating conditions were examined based on these events and simulations: (1) when the unit is operating at rated Real Power in MW with a level of Reactive Power output in Mvar which is equivalent to 150 percent times the rated MW value (representing some level of field-forcing) and (2) when the unit is operating at its declared low active Real Power operating limit (e.g., 40 percent of rated Real Power) with a level of Reactive Power output in Mvar which is equivalent to 175 percent times the rated MW value (representing some additional level of field-forcing).

Both conditions noted above are evaluated with the GSU transformer high-side voltage at 0.85 per unit. These load operating points are believed to be conservatively high levels of Reactive Power out of the generator with a 0.85 per unit high-side voltage which was based on these observations. However, for the purposes of this standard it was determined that the second load point (40 percent) offered no additional benefit and only increased the complexity for an entity to determine how to comply with the standard. Given the conservative nature of the criteria, which may not be achievable by all generating units, an alternate method is provided to determine the Reactive Power output by simulation. Also, to account for Reactive Power losses in the GSU transformer, a reduced level of output of 120 percent times the rated MW value is provided for relays applied at the high-side of the GSU transformer and on Elements that connect a GSU transformer to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant.

The phrase, "while maintaining reliable fault protection" in Requirement R1, describes that the Generator Owner, Transmission Owner, and Distribution Provider is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the Transmission system, and this standard is not intended to result in the loss of these protection functions. Instead, it is suggested that the Generator Owner, Transmission Owner, and Distribution Provider consider both the requirement within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

[5] http://www.nerc.com/docs/pc/spctf/Gen%20Prot%20Coord%20Rev1%20Final%2007-30-2010.pdf

For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be possible to meet this purpose by replacing the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the Generator Owner, Transmission Owner, and Distribution Provider must understand the applications of Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria ("Table 1") in determining the settings that it must apply to each of its load-responsive protective relays to prevent an unnecessary trip of its generator during the system conditions anticipated by this standard.

Applicability

To achieve the reliability objective of this standard it is necessary to include all load-responsive protective relays that are affected by increased generator output in response to system disturbances. This standard is therefore applicable to relays applied by the Generator Owner, Transmission Owner, and Distribution Provider at the terminals of the generator, GSU transformer, unit auxiliary transformer (UAT), Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, and Elements utilized in the aggregation of dispersed power producing resources.

The Generator Owner's interconnection facility (in some cases labeled a "transmission Facility" or "generator leads") consists of Elements between the GSU transformer and the interface with the portion of the Bulk Electric System (BES) where Transmission Owners take over the ownership. This standard does not use the industry recognized term "generator interconnection Facility" consistent with the work of Project 2010-07 (Generator Requirements at the Transmission Interface), because the term generator interconnection Facility implies ownership by the Generator Owner. Instead, this standard refers to these Facilities as "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant" to include these Facilities when they are also owned by the Transmission Owner or Distribution Provider. The load-responsive protective relays in this standard for which an entity shall be in compliance is dependent on the location and the application of the protective functions. Figures 1, 2, and 3 illustrate various generator interface connections with the Transmission system.

Figure 1

Figure 1 is a single (or set) of generators connected to the Transmission system through a radial line that is used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 located on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-1 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relay R2 located on the incoming source breaker CB102 to the generating plant applies relaying that primarily protects the line by using line differential relaying from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-1 and an appropriate option for the application from Table 1 (e.g., 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-1 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

In this particular case, the applicable responsible entity's directional relay R3 located on breaker CB103 at Bus B looking toward Bus A (i.e., generation plant) is not included in either loadability standard (i.e., PRC-023 or PRC-025) since it is not affected by increased generator output in response to system disturbances described in this standard or by increased transmission system loading described in PRC-023. Any protective element set to protect in the direction from Bus A to B is included within the PRC-025-1 standard. PRC-025-1 is applicable to Relay R3, for example, if the relay is applied and set to trip for a reverse element directional toward the Transmission system.

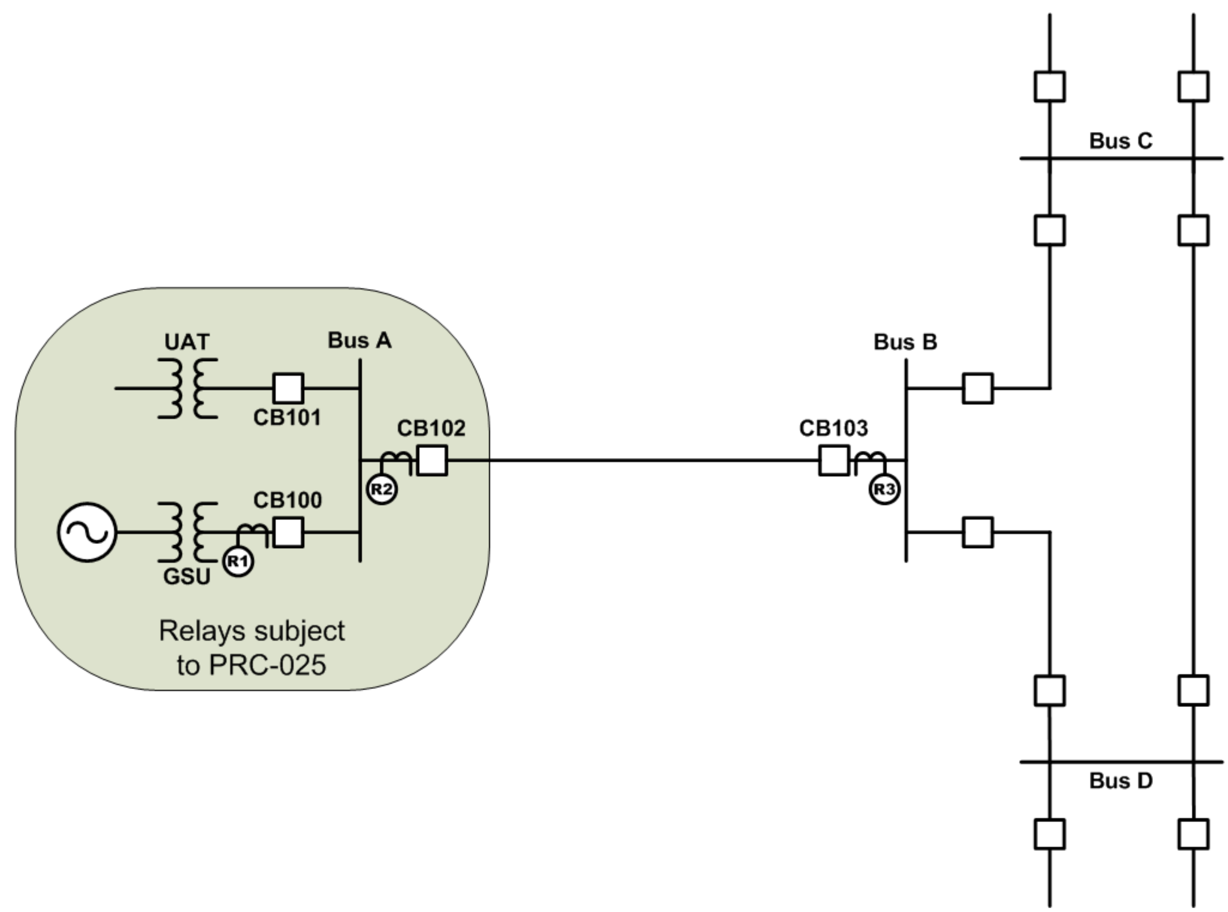


Figure 1. Generation exported through a single radial line.

Figure 2

Figure 2 is an example of a single (or set) of generators connected to the Transmission system through multiple lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-1 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relays R2 and R3 located on the incoming source breakers CB102 and CB103 to the generating plant applies relaying that primarily protects the line from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-1 and an appropriate option for the application from Table 1 (e.g., Options 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-1 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

In this particular case, the applicable responsible entity's directional relay R4 and R5 located on the breakers CB104 and CB105, respectively at Bus B looking into the generation plant are not included in either loadability standard (i.e., PRC-023 or PRC-025) since they are not subject to the stressed loading requirements described in the standard or by increased transmission system loading described in PRC-023. Any protective element set to protect in the direction from Bus A to B is included within the PRC-025-1 standard. PRC-025-1 is applicable to Relay R4 and R5, for example, if the relays are applied and set to trip for a reverse element directional toward the Transmission system.

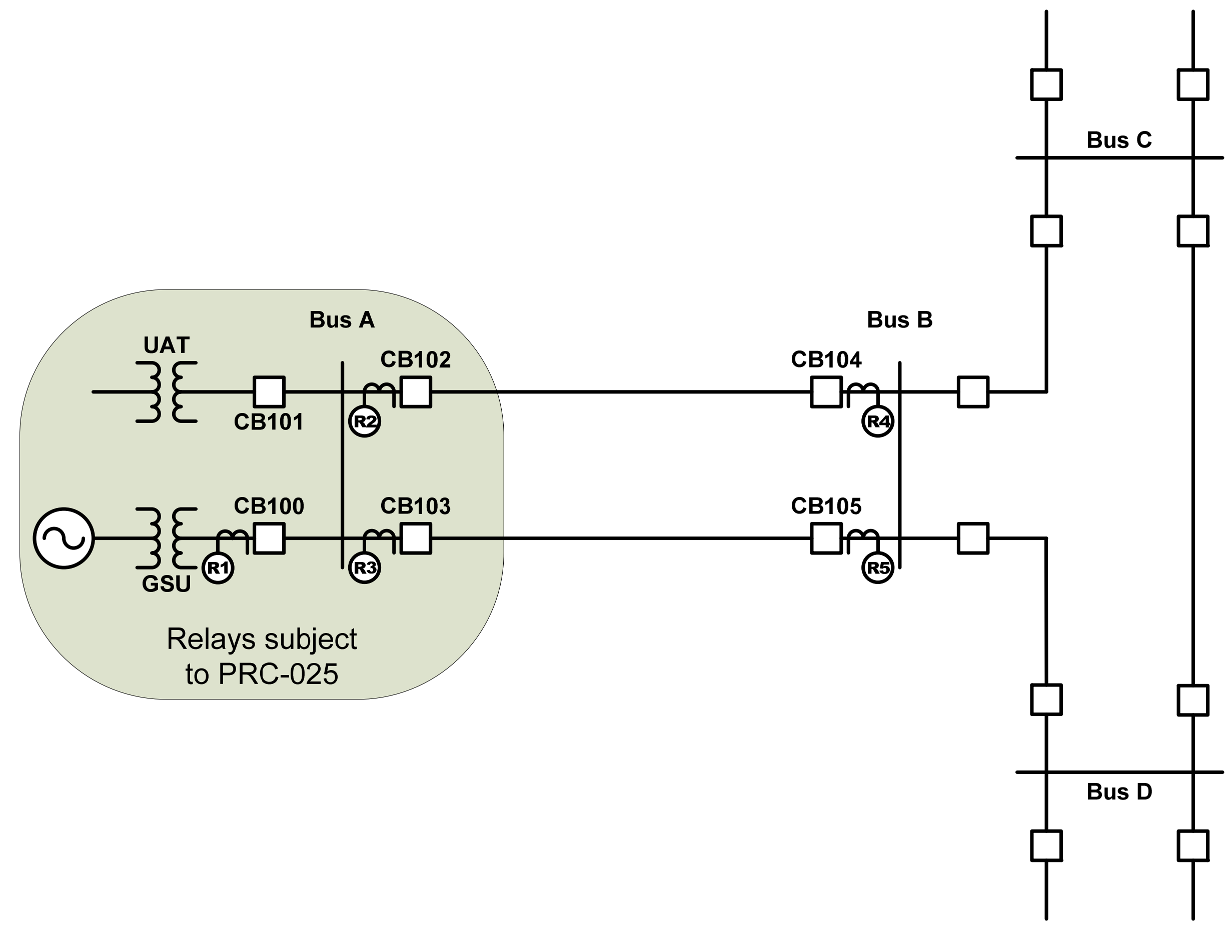


Figure 2. Generation exported through multiple radial lines.

Figure 3

Figure 3 is example a single (or set) of generators exporting power dispersed through multiple lines to the Transmission system through a network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus C or Bus D. Under this application, relay R1 would apply the applicable loadability requirement in PRC-025-1 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Therefore, the applicable responsible entity would be responsible for the load-responsive protective relays R2 and R3 under the PRC-023 standard. The applicable responsible entity's loadability relays R4 and R5 located on the breakers CB104 and CB105 at Bus C and D are also subject to the requirements of the PRC-023 standard.

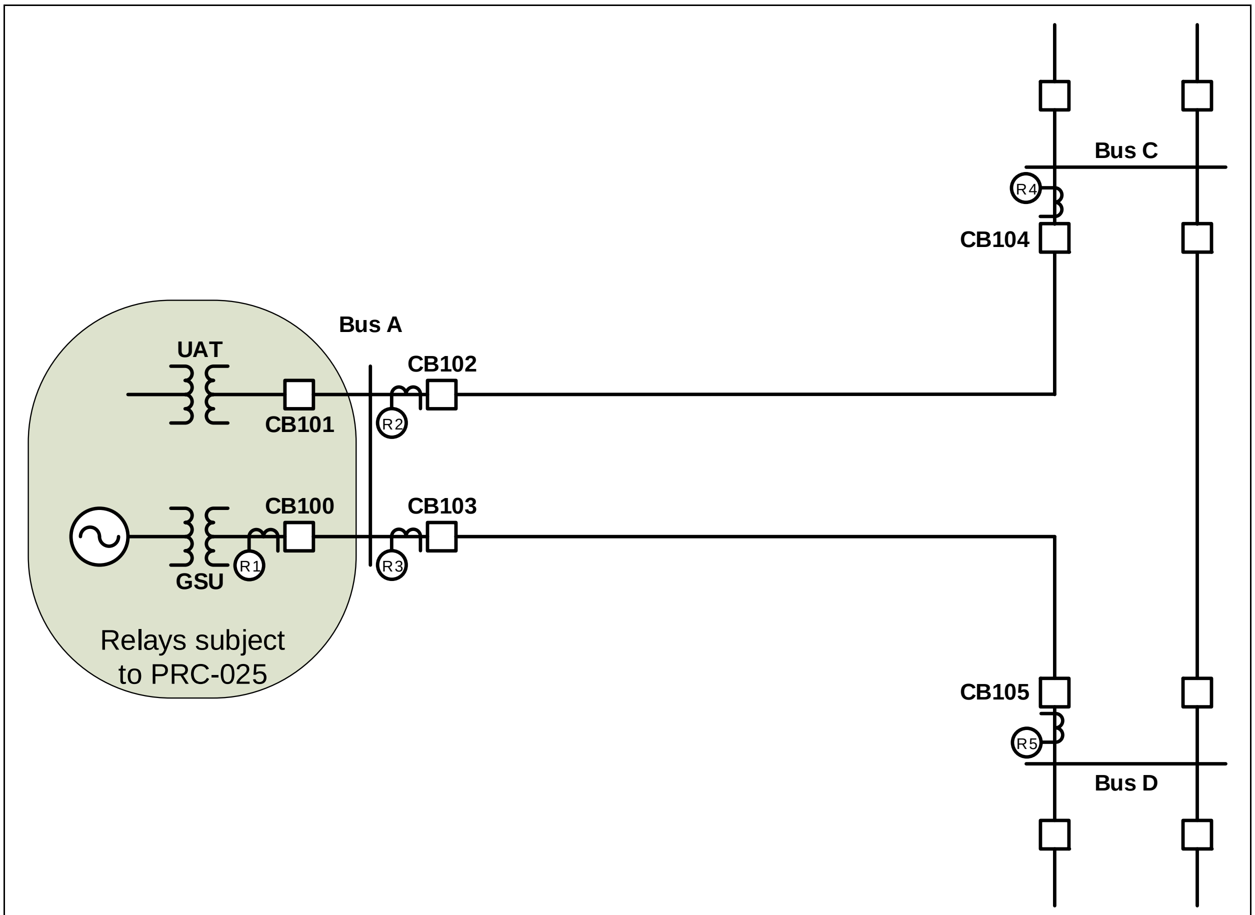


Figure 3. Generation exported through a network.

Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a "collector system") consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.

This standard is also applicable to the UATs that supply station service power to support the on-line operation of generating units or generating plants. These transformers are variably referred to as station power, unit auxiliary transformer(s), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Inclusion of these transformers satisfies a directive in FERC Order No. 733, paragraph 104, which directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT(s) that supply normal station service for a generating unit.

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as "field-forcing," results in the Reactive Power output exceeding the steady-state capability of the generator and may result in operation of generation system load-responsive protective relays if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1 are based on 0.85 per unit of Transmission system nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had not other undesired behavior occurred.

The dynamic load levels specified in Table 1 under column "Pickup Setting Criteria" are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the GSU transformer. These values are based on records from the events leading to the August 14, 2003 blackout, other subsequent System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified criteria represent conservative but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20 percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1a (i.e., 0.95 per unit) and 1b (i.e., 0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output Option 1c (i.e., simulation) was developed to allow the Generator Owner, Transmission Owner, or Distribution Provider to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

Dispersed Generation

This standard is applicable to dispersed generation such as wind farms and solar arrays. The intent of this standard is to ensure the aggregate facility as defined above will remain on-line during a system disturbance; therefore, all output load-responsive protective elements associated with the facility are included in PRC -025.

Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above are included in PRC-025-1. Load-responsive protective relays that are applied on Elements that connect these individual generating units through the point of interconnection with the Transmission system are within the scope of PRC-025-1. For example, feeder overcurrent relays and feeder step-up transformer overcurrent relays (see Figure 5) are included because these relays are challenged by generator loadability.

In the case of solar arrays where there are multiple voltages utilized in converting the solar panel DC output to a 60Hz AC waveform, the “terminal” is defined at the 60Hz AC output of the inverter-solar panel combination.

Asynchronous Generator Performance

Asynchronous generators, however, do not have excitation systems and will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before a crowbar function will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated MW.

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1 (i.e., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19) for asynchronous generator installations.

Synchronous Generator Simulation Criteria

The Generator Owner, Transmission Owner, or Distribution Provider who elects a simulation option to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage on the high-side of the GSU transformer. This can be simulated by means such as modeling the connection of a shunt reactor on the Transmission system to lower the GSU transformer high-side voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in MW as reported to the Transmission Planner. The simulation is used to determine the Reactive Power and voltage to be used to calculate relay pickup setting limits. The Reactive Power value obtained by simulation is the highest simulated level of Reactive Power achieved during field-forcing. The voltage value obtained by simulation is the simulated voltage coincident with the highest Reactive Power achieved during field-forcing. These values of Reactive Power and voltage correspond to the minimum apparent impedance and maximum current observed during field-forcing.

Phase Distance Relay – Directional Toward Transmission System (21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup GSU transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current.

Section 4.6.1.1 of IEEE C37.102-2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault* ***that is not cleared***

> ***by the transmission line breakers.*** *In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and* ***normal loading conditions.*** *However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers* ***to optimize coordination while still protecting the turbine generator****. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders [sic] can prevent misoperation for these conditions.* ***Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.*** *With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. The normal zone-2 time-delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting.”*

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable fault protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability.

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may result in a relay characteristic that overlaps the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. Overlap of the relay characteristic and generator capability could result in tripping the generating unit for a loading condition within the generating unit capability. The examples in Appendix E of the Power Plant and Transmission System Protection Coordination technical reference document illustrate the potential for, and need to avoid, encroaching on the generating unit capability.

Phase Time Overcurrent Relay (51)

See section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the Table 1 setting criteria established within the Table 1 options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator operates synchronous or asynchronous.

Phase Time Overcurrent Relay – Voltage-Restrained (51V-R)

Phase time overcurrent voltage-restrained relays (51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup GSU transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by voltage-restrained and voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. See section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Time Overcurrent Relay – Voltage Controlled (51V-C)

Phase time overcurrent voltage-controlled relays (51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms.

See section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67)

See section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of the phase time overcurrent protection function. The basis for setting directional and non-directional time overcurrent relays is similar. Note that the Table 1setting criteria established within the Table 1 options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator operates synchronous or asynchronous.

Table 1, Options

Introduction

The margins in the Table 1 options are based on guidance found in the Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Relay Connections

Figures 4 and 5 below illustrate the connections for each of the Table 1 options provided in PRC-025-1, Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria.

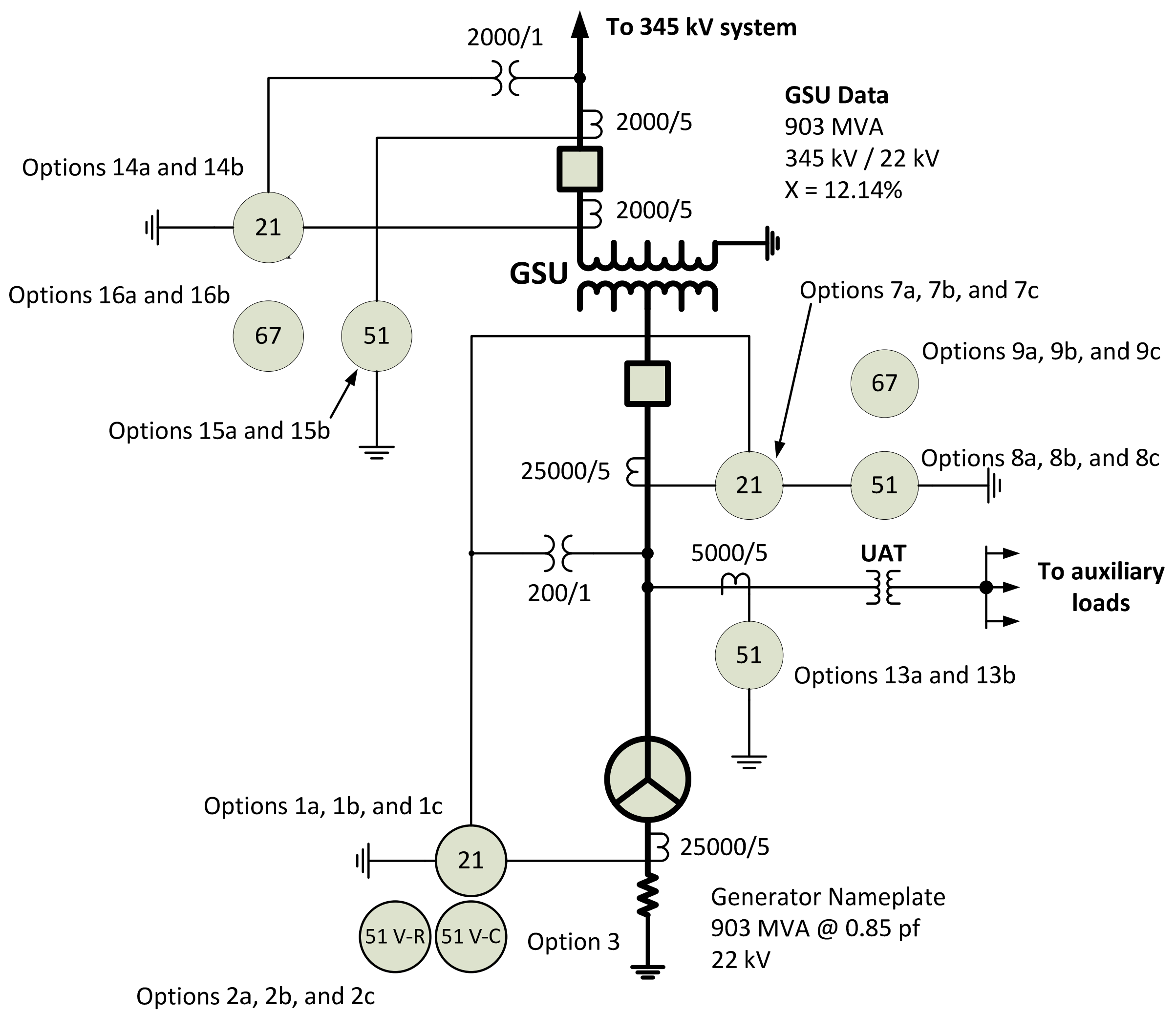


Figure 4. Relay Connection for corresponding synchronous options.

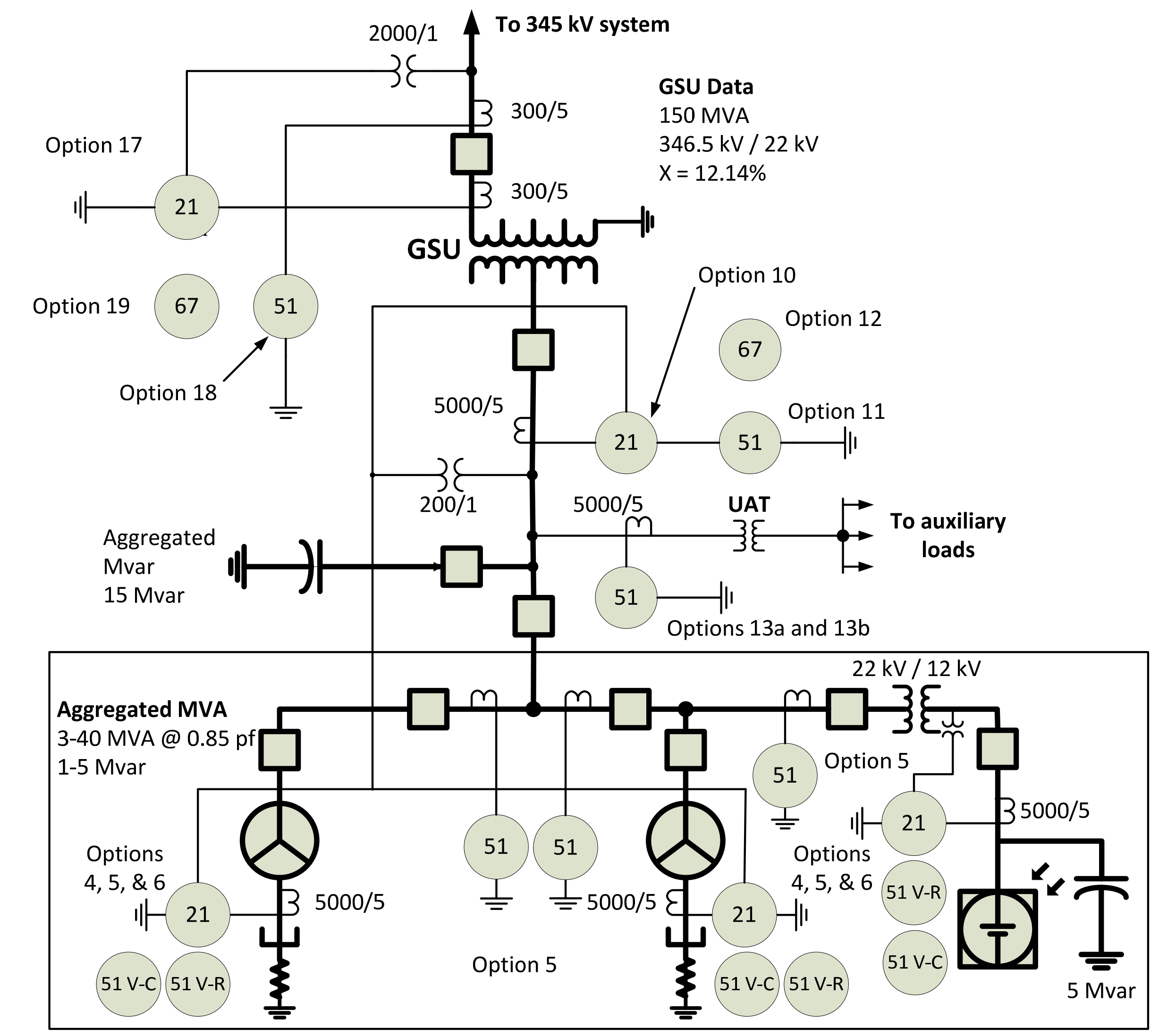


Figure 5. Relay Connection for corresponding asynchronous options including inverter-based installations.

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer and accounts for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element is set less than the calculated impedance derived from 115percent of: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 1c, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage-Restrained (51V-R) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase time overcurrent relays which change their sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer and accounts for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element is set greater than the calculated current derived from 115 percent of: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting is set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (21) (Option 4)

Table 1, Option 4 is provided for assessing loadability for asynchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 4, the impedance element is set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase Time Overcurrent Relay – Voltage-Restrained (51V-R) (Option 5)

Table 1, Option 5 is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which change their sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 5 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 5, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting is set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (21) (Options 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability for GSU transformers applying phase distance relays that are directional toward the Transmission system on synchronous generators that are connected to the generator-side of the GSU transformer of a synchronous generator. Where the relay is connected on the high-side of the GSU transformer, use Option 14.

Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer and accounts for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 7a.

Option 7c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 7a and 7b the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 7c, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Time Overcurrent Relay (51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability for GSU transformers applying phase time overcurrent relays on synchronous generators that are connected to the generator-side of the GSU transformer of a synchronous generator. Where the relay is connected on the high-side of the GSU transformer, use Option 15.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer and accounts for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 8a.

Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 8a and 8b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 8c, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Options 9a, 9b and 9c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability for GSU transformers applying phase directional time overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of a synchronous generator. Where the relay is connected on the high-side of the GSU transformer, use Option 16.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer and accounts for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 9a.

Option 9c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 9a and 9b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 9c, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (21) (Option 10)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Table 1, Option 10 is provided for assessing loadability for GSU transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document. Where the relay is connected on the high-side of the GSU transformer, use Option 17.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 10, the impedance element is set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Time Overcurrent Relay (51) (Option 11)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11 is provided for assessing loadability for GSU transformers applying phase time overcurrent relays on asynchronous generators that are connected to the generator-side of the GSU transformer. Where the relay is connected on the high-side of the GSU transformer, use Option 18.

Option 11 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 11, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability for GSU transformers applying phase directional time overcurrent relays directional toward the Transmission System on asynchronous generators that are connected to the generator-side of the GSU transformer of an asynchronous generator. Where the relay is connected on the high-side of the GSU transformer, use Option 19.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 12, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Unit Auxiliary Transformers Phase Time Overcurrent Relay (51) (Options 13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT that supply normal station service for a generating unit. For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, Options 13a and 13b provide two options for addressing phase time overcurrent relaying applied at the high-side of UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator isolated phase bus (IPB) or iso-phase bus. Phase time overcurrent relays applied at the high-side of the UAT that remove the transformer from service resulting in an immediate (e.g., via lockout or auxiliary tripping relay operation) or consequential trip of the associated generator are to be compliant with the relay setting criteria in this standard. Due to the complexity of the application of low-side overload relays for single or multi-winding transformers, phase time overcurrent relaying applied to the UAT are not addressed in this standard. These relays include, but are not limited to, a relay used for arc flash protection, feeder protection relays, breaker failure, and relays whose operation may result in a generator runback. Although the UAT is not directly in the output path from the generator to the Transmission system, it is an essential component for operation of the generating unit or plant.

Refer to the Figures 6 and 7 below for example configurations:

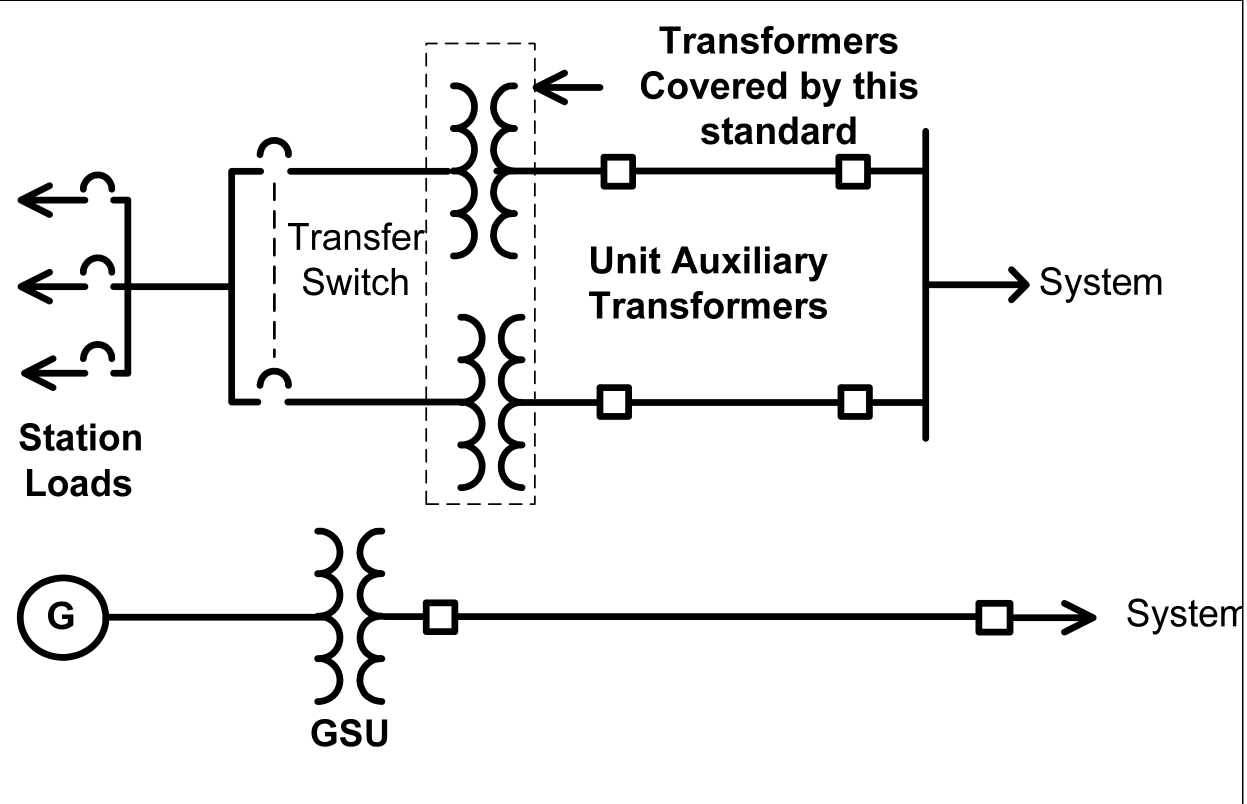


Figure-6 – Auxiliary Power System (independent from generator).

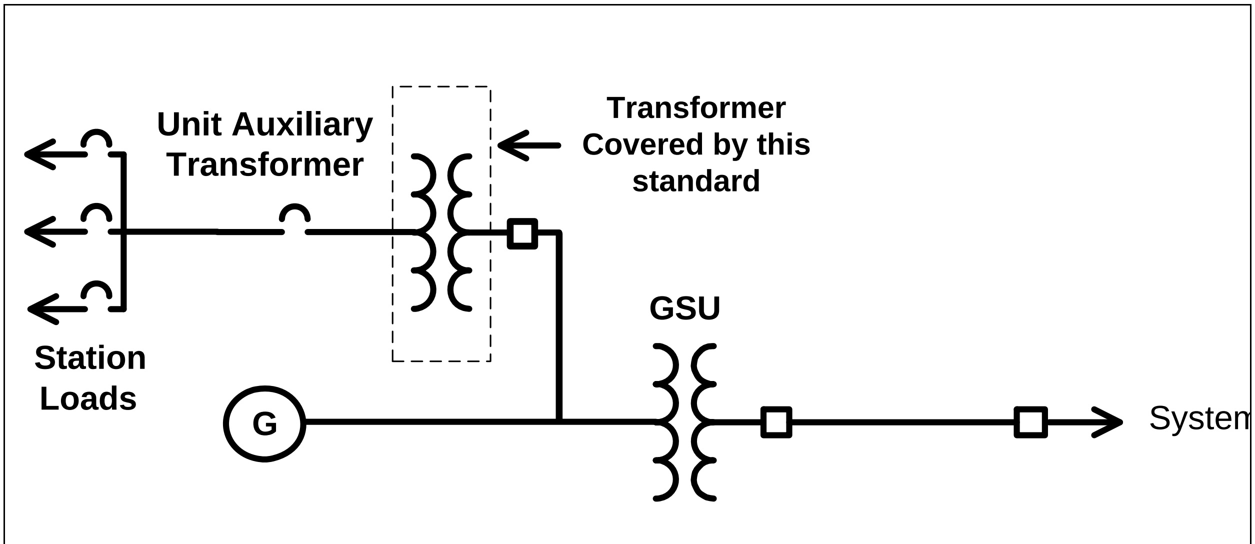


Figure-7 – Typical auxiliary power system for generation units or plants.

The UATs supplying power to the unit or plant electrical auxiliaries are sized to accommodate the maximum expected overall UAT load demand at the highest generator output. Although the transformer nameplate MVA size normally includes capacity for future loads as well as capacity for starting of large induction motors on the original unit or plant design, the nameplate MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (i.e., 13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer phase time overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b are based on the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding of the UAT.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Transmission Planner. This allows for a reduced setting pickup compared to Option 13a and the entity's relay setting philosophy. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the Transmission Planner.

The performance of the UAT loads during stressed system conditions (i.e., depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115 percent) and use a generator bus voltage of 1.0 per unit. A minimum pickup current based on 150 percent of maximum transformer nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (21) (Options 14a and 14b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 14 is used for these relays as well.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 14a reflects a 0.85 per unit Transmission system voltage; therefore, establishing that the impedance value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the GSU transformer is not necessary. Option 14b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 14a, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other application to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the impedance element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Time Overcurrent Relay (51) (Options 15a and 15b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 15 is used for these relays as well.

Table 1, Options 15a and 15b, establish criteria for phase time overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 15a reflects a 0.85 per unit Transmission system voltage; therefore, establishing that the current value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the GSU transformer is not necessary. Option 15b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 15a, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other application to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Options 16a and 16b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 16 is used for these relays as well.

Table 1, Options 16a and 16b, establish criteria for phase directional time overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 16a reflects a 0.85 per unit Transmission system voltage; therefore, establishing that the current value used for applying the interconnection Facilities phase directional time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the GSU transformer is not necessary. Option 16b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 16a, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other application to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (21) (Option 17)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from operating during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer to calculate the impedance from the maximum aggregate nameplate MVA. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant.

For Option 17, the impedance element is set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Time Overcurrent Relay (51) (Option 18)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase time overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from operating during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer to calculate the current from the maximum aggregate nameplate MVA. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant.

For Option 18, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 19)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document.

Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional time overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from operating during the dynamic conditions anticipated by this standard. Option 19 applies a 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer to calculate the current from the maximum aggregate nameplate MVA. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant.

For Option 19, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations.	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA @ rated pf):	$GEN_{Synch\_nameplate} = 903\ MVA$
	$pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen\_nom} = 22\ kV$
Real Power output in MW as reported to the TP:	$P_{Synch\_reported} = 700.0\ MW$
Generator step-up (GSU) transformer rating:	$MVA_{GSU} = 903\ MVA$
GSU transformer reactance (903 MVA base):	$X_{GSU} = 12.14\%$
GSU transformer MVA base:	$MVA_{base} = 767.6\ MVA$
GSU transformer turns ratio:	$GSU_{ratio} = \frac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer (CT) ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer (PT) ratio low-side:	$PT_{ratio} = \frac{200}{1}$
PT ratio high-side:	$PT_{ratio\_hv} = \frac{2000}{1}$
Unit auxiliary transformer (UAT) nameplate:	$UAT_{nameplate} = 60\ MVA$
UAT low-side voltage:	$V_{UAT} = 13.8\ kV$
UAT CT ratio:	$CT_{UAT} = \frac{5000}{5}$
CT high voltage ratio:	$CT_{ratio\_hv} = \frac{2000}{5}$
Reactive Power output of static reactive device:	$MVAR_{static} = 15\ Mvar$
Reactive Power output of static reactive device generation:	$MVAR_{gen\_static} = 5\ Mvar$

Example Calculations.	
Asynchronous generator nameplate (MVA @ rated pf):	$GEN_{Asynch\_nameplate} = 40\ MVA$
	$pf = 0.85$
Asynchronous CT ratio:	$CT_{Asynch\_ratio} = \frac{5000}{5}$
Asynchronous high voltage CT ratio:	$CT_{Asynch\_ratio\_hv} = \frac{300}{5}$

Example Calculations: Option 1a

Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (21) directional toward the Transmission system.

Real Power output (P):

Eq. (1) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (2) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (3) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (4) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (5) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

$$Z_{pri} = 0.321\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (6) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

Example Calculations: Option 1a

$$Z_{sec} = 0.321\angle 58.7°\,\Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.321\angle 58.7°\,\Omega \times 25$$

$$Z_{sec} = 8.035\angle 58.7°\,\Omega$$

To satisfy the 115% margin in Option 1a:

Eq. (7) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.035\angle 58.7°\,\Omega}{1.15}$$

$$Z_{\sec limit} = 6.9873\angle 58.7°\,\Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (8) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.9873\,\Omega}{\cos(85.0° - 58.7°)}$$

$$Z_{max} < \frac{6.9873\,\Omega}{0.896}$$

$$Z_{max} < 7.793\angle 85.0°\,\Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance relay (21) directional toward the Transmission system. This option requires calculating low-side voltage taking into account voltage drop across the GSU transformer. Similarly these calculations may be applied to Option 7b for GSU transformers applying a phase distance relay (21) directional toward the Transmission system.

Real Power output (P):

Eq. (9) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Example Calculations: Options 1b and 7b

Reactive Power output (Q):

Eq. (10) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on a 767.6 MVA base (MVA_{base}):

Real Power output (P):

Eq. (11) $P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (12) $Q_{pu} = \frac{Q}{MVA_{base}}$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance (X_{pu}):

Eq. (13) $X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (14) $\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times [V_{high-side}]\right)}\right]$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (15)
$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (16)
$$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (17)
$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (18)
$$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Example Calculations: Options 1b and 7b

Apparent power (S):

Eq. (19) $S = P_{Synch\_reported} + jQ$

$S = 700.0\ MW + j1151.3\ Mvar$

$S = 1347.4\angle 58.7°\ MVA$

Primary impedance (Z_{pri}):

Eq. (20) $Z_{pri} = \frac{V_{bus}^2}{S^*}$

$$Z_{pri} = \frac{(21.90\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

$Z_{pri} = 0.356\angle 58.7°\ \Omega$

Secondary impedance (Z_{sec}):

Eq. (21) $Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$Z_{sec} = 0.356\angle 58.7°\ \Omega \times 25$

$Z_{sec} = 8.900\angle 58.7°\ \Omega$

To satisfy the 115% margin in Options 1b and 7b:

Eq. (22) $Z_{\sec limit} = \frac{Z_{sec}}{115\%}$

$$Z_{\sec limit} = \frac{8.900\angle 58.7°\ \Omega}{1.15}$$

$Z_{\sec limit} = 7.74\angle 58.7°\ \Omega$

$\theta_{transient\ load\ angle} = 58.7°$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (23) $Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$

$$Z_{max} < \frac{7.74\ \Omega}{\cos(85.0^{\circ} - 58.7°)}$$

Example Calculations: Options 1b and 7b

$$Z_{max} < \frac{7.74\,\Omega}{0.8965}$$

$$Z_{max} < 8.633\angle 85.0°\,\Omega$$

Example Calculations: Options 1c and 7c

Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

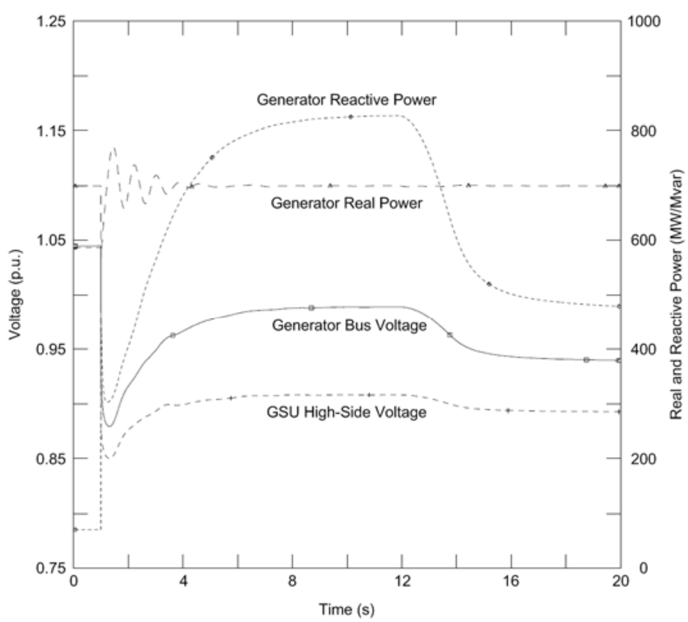
In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus} = 0.989 \times V_{gen\_nom} = 21.76\ k\mathrm{V}$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$



Example Calculations: Options 1c and 7c

Apparent power (S):

Eq. (24) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (25) $Z_{pri} = \frac{V_{bus}^2}{S^*}$

$$Z_{pri} = \frac{(21.76\ kV)^2}{1083.8\angle -49.8°\ MVA}$$

$$Z_{pri} = 0.437\angle 49.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (26) $Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times 25$$

$$Z_{sec} = 10.92\angle 49.8°\ \Omega$$

To satisfy the 115% margin in the requirement in Options 1c and 7c:

Eq. (27) $Z_{\sec limit} = \frac{Z_{sec}}{115\%}$

$$Z_{\sec limit} = \frac{10.92\angle 49.8°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 9.50\angle 49.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 49.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (28) $Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$

$$Z_{max} < \frac{9.50\ \Omega}{\cos(85.0^{\circ} - 49.8°)}$$

Example Calculations: Options 1c and 7c

$$Z_{max} < \frac{9.50\ \Omega}{0.8171}$$

$$Z_{max} < 11.63\angle 85.0°\ \Omega$$

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase time overcurrent (51V-R) voltage restrained relay:

Real Power output (P):

Eq. (29) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (30) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (31) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (32) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (33) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

Example Calculations: Option 2a

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (34) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Option 2a:

Eq. (35) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase time overcurrent (51V-R) voltage restrained relay:

Real Power output (P):

Eq. (36) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (37) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Example Calculations: Option 2b

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (MVA_{base}).

Real Power output (P):

Eq. (38) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (39) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (40) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (41) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times [V_{high-side}]\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (42) $$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

Example Calculations: Option 2b

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (43) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (44) $$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (45) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (46) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

Example Calculations: Option 2b

$$S = 1347.4\angle 58.7° \; MVA$$

Primary current (I_{pri}):

Eq. (47) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4 \; MVA}{1.73 \times 21.90 \; kV}$$

$$I_{pri} = 35553 \; A$$

Secondary current (I_{sec}):

Eq. (48) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553 \; A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111 \; A$$

To satisfy the 115% margin in Option 2b:

Eq. (49) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.111 \; A \times 1.15$$

$$I_{\sec limit} > 8.178 \; A$$

Example Calculations: Option 2c

Option 2c represents a more involved, more precise setting of the overcurrent element for the phase time overcurrent (51V-R) voltage restrained relay. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 2a and 2b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.

In this simulation the following values are derived:

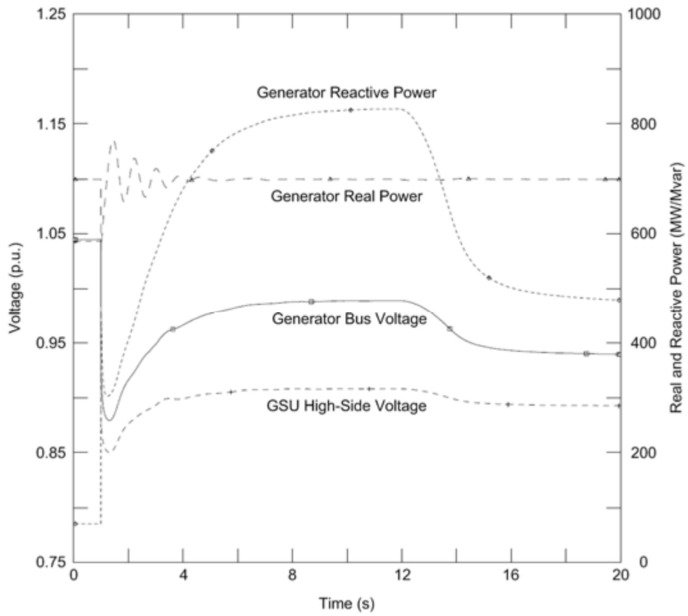
$$Q = 827.4 \; Mvar$$

$$V_{bus} = 0.989 \times V_{gen\_nom} = 21.76 \; kV$$

Example Calculations: Option 2c

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$



Apparent power (S):

Eq. (50) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary current (I_{pri}):

Eq. (51) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (52) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

Example Calculations: Option 2c

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Option 2c:

Eq. (53) $I_{\sec limit} > I_{sec} \times 115\%$

$$I_{\sec limit} > 5.758\ A \times 1.15$$

$$I_{\sec limit} > 6.622\ A$$

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (51V-C) – voltage controlled relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (54) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

The voltage setting shall be set less than 75% of the generator bus voltage:

Eq. (55) $V_{setting} < V_{gen} \times 75\%$

$$V_{setting} < 21.9\ kV\ \times 0.75$$

$$V_{setting} < 16.429\ kV$$

Example Calculations: Option 4

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance relay (21) – directional toward the Transmission system.

Real Power output (P):

Eq. (56) $P = GEN_{Asych\_nameplate} \times pf$

Example Calculations: Option 4

$$P = 40\ MVA\ \times 0.85$$

$$P = 34.0\ MW$$

Reactive Power output (Q):

Eq. (57) $$Q = GEN_{Async\_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q = 40\ MVA \times \sin(\cos^{-1}(0.85))$$

$$Q = 21.1\ Mvar$$

Option 4, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (58) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (59) $$S = P + jQ$$

$$S = 34.0\ MW + j21.1\ Mvar$$

$$S = 40.0\angle 31.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (60) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{40.0\angle -31.8°\ MVA}$$

$$Z_{pri} = 11.99\ \angle 31.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (61) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times 5$$

Example Calculations: Option 4

$$Z_{sec} = 59.95\ \angle 31.8°\ \Omega$$

To satisfy the 130% margin in Option 4:

Eq. (62) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{59.95\angle 31.8°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 46.12\angle 31.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 31.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (63) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos\left(\theta_{MTA} - \theta_{transient\ load\ angle}\right)}$$

$$Z_{max} < \frac{46.12\ \Omega}{\cos(85.0° - 31.8°)}$$

$$Z_{max} < \frac{46.12\ \Omega}{0.599}$$

$$Z_{max} < 77.0\angle 85.0°\ \Omega$$

Example Calculations: Option 5

This represents the calculation for three asynchronous generators applying a phase time overcurrent (51V-R) – voltage-restrained relay. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (64) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA\ \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (65) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Example Calculations: Option 5

Option 5, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (66) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (67) $S = P + jQ$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (68) $I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (69) $I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Option 5:

Eq. (70) $I_{\mathrm{sec}\,limit} > I_{sec} \times 130\%$

$$I_{\mathrm{sec}\,limit} > 3.473\angle -39.2°\ A \times 1.30$$

$$I_{\mathrm{sec}\,limit} > 4.52\angle -39.2°\ A$$

Example Calculations: Options 7a and 10

This represents the calculation for a mixture of asynchronous (i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations) applying a phase distance relay (21) – directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Synchronous Generation (Option 7a)

Real Power output (P_{sync}):

Eq. (71) $P_{Synch} = GEN_{Synch\_nameplate} \times pf$

$$P_{Synch} = 903\ MVA \times 0.85$$

$$P_{Synch} = 767.6\ MW$$

Reactive Power output (Q_{synch}):

Eq. (72) $Q_{Synch} = 150\% \times P_{Synch}$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ MW$$

Apparent power (S_{Synch}):

Eq. (73) $S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

Asynchronous Generation (Option 10)

Real Power output (P_{Asynch}):

Eq. (74) $P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (75) $Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Apparent power (S_{Asynch}):

Eq. (76) $S_{Asynch} = P_{Asynch} + jQ_{Asynch}$

Example Calculations: Options 7a and 10

$$S_{Asynch} = 102.0\ MW + j83.2\ Mvar$$

Options 7a and 10, Table 1 – Bus Voltage, Option 7a specifies 0.95 per unit of the high-side nominal voltage for the generator bus voltage and Option 10 specifies 1.0 per unit of the high-side nominal voltage for generator bus voltage. Due to the presence of the synchronous generator, the 0.95 per unit bus voltage will be used as (V_{gen}) as it results in the most conservative voltage:

Eq. (77) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S) accounted for 115% margin requirement for a synchronous generator and 130% margin requirement for an asynchronous generator:

Eq. (78) $$S = 115\% \times \left(P_{Synch\_reported} + jQ_{Synch}\right) + \ 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S = 1.15 \times (700.0\ MW + j1151.3\ Mvar) + 1.30\ \times (102.0\ MW + j83.2\ Mvar)$$

$$S = 1711.8\ \angle 56.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (79) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1711.8\angle -56.8°\ MVA}$$

$$Z_{pri} = 0.2527\angle 56.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (80) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times 25$$

$$Z_{sec} = 6.32\angle 56.8°\ \Omega$$

Example Calculations: Options 7a and 10

No additional margin is needed; therefore, the margin is 100% because the synchronous apparent power has been multiplied by 1.15 (115%) and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 85 to satisfy the margin requirements in Options 7a and 10:

Eq. (81) $$Z_{sec\,limit} = \frac{Z_{sec}}{100\%}$$

$$Z_{sec\,limit} = \frac{6.32\ \angle 56.8°\ \Omega}{1.00}$$

$$Z_{sec\,limit} = 6.32\ \angle 56.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 56.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (82) $$Z_{max} < \frac{|Z_{sec\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.32\ \Omega}{\cos(85.0° - 56.8°)}$$

$$Z_{max} < \frac{6.32\ \Omega}{0.881}$$

$$Z_{max} < 7.17\angle 85.0°\ \Omega$$

Example Calculations: Options 8a and 9a

Options 8a and 9a represents the simplest calculation for synchronous generators applying a phase time overcurrent (51) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (83) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (84) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

Example Calculations: Options 8a and 9a

$$Q = 1151.3\ Mvar$$

Options 8a and 9a, Table 1 – Bus Voltage, calls for a generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer generator bus voltage (V_{gen}):

Eq. (85) $$V_{gen} = 0.95\ p.u.\times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (86) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (87) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (88) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Options 8a and 9a:

Eq. (89) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Options 8b and 9b

Options 8b and 9b represents a more complex calculation for synchronous generators applying a phase time overcurrent (51) relay. The following uses the $GEN_{Synch\ nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (90) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (91) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (MVA_{base}).

Real Power output (P):

Eq. (92) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (93) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (94) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (95) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Eq. (96) $$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (97) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (98) $$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

Example Calculations: Options 8b and 9b

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (99) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u.\times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (100) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (101) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (102) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Options 8b and 9b:

Eq. (103) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.111\ A \times 1.15$$

$$I_{\sec limit} > 8.178\ A$$

Example Calculations: Options 8a, 9a, 11, and 12

This represents the calculation for a mixture of asynchronous and synchronous generators applying a phase time overcurrent. In this application it was assumed 20 Mvar of total static compensation was added. The current transformers (CT) are located on the low-side of the GSU transformer.

Synchronous Generation (Options 8a and 9a)

Real Power output (P_{Synch}):

Eq. (104) $$P_{Synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times .85$$

$$P_{Synch} = 767.6\ MW$$

Reactive Power output (Q_{Synch}):

Eq. (105) $$Q_{Synch} = 150\% \times P_{Synch}$$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ Mvar$$

Apparent power (S_{Synch}):

Eq. (106) $$S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

$$S_{Synch} = 1347.4\ \angle 58.7°\ MVA$$

Option 8a, Table 1 – calls for a 0.95 per unit of the high-side nominal voltage for generator bus voltage (V_{gen}):

Eq. (107) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Primary current ($I_{pri\text{-}sync}$):

Eq. (108) $$I_{pri-sync} = \frac{115\% \times S^*_{Synch}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-sync} = \frac{1.15 \times (1347.4\ \angle -58.7°\ MVA)}{1.73 \times 20.81\ kV}$$

$$I_{pri-sync} = 43061\ \angle -58.7°\ A$$

Example Calculations: Options 8a, 9a, 11, and 12

Asynchronous Generation (Options 11 and 12)

Real Power output (P_{Asynch}):

Eq. (109) $$P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (110) $$Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Option 11, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}), however due to the presence of synchronous generator 0.95 per unit bus voltage will be used:

Eq. (111) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S_{Asynch}):

Eq. (112) $$S_{Asynch} = 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S_{Asynch} = 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S_{Asynch} = 171.1\ \angle 39.2°\ MVA$$

Primary current ($I_{pri\text{-}async}$):

Eq. (113) $$I_{pri-async} = \frac{S_{Asych}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-async} = \frac{171.1\ \angle -39.2°\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri-async} = 4755\ \angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (114) $$I_{sec} = \frac{I_{pri-sync}}{CT_{ratio}} + \frac{I_{pri-async}}{CT_{ratio}}$$

Example Calculations: Options 8a, 9a, 11, and 12

$$I_{sec} = \frac{43061 \angle -58.7° \, A}{\frac{25000}{5}} + \frac{4755 \angle -39.2° \, A}{\frac{25000}{5}}$$

$$I_{sec} = 9.514 \angle -56.8° \, A$$

No additional margin is needed; therefore, the margin is 100% because the synchronous apparent power has been multiplied by 1.15 (115%) in Equation 94 and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 98:

Eq. (115) $I_{\sec limit} > I_{sec} \times 100\%$

$$I_{\sec limit} > 9.514 \angle -56.8° \, A \times 1.00$$

$$I_{\sec limit} > 9.514 \angle -56.8° \, A$$

Example Calculations: Options 8c and 9c

This example uses Option 15b as a simulation example for a synchronous generator applying a phase time overcurrent relay. In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU transformer.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

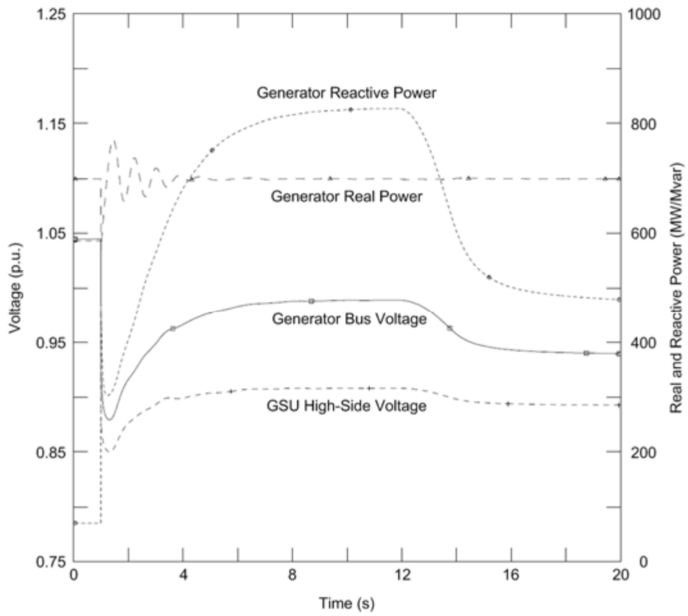
$$Q = 827.4 \, Mvar$$

$$V_{bus} = 0.989 \times V_{gen} = 21.76 \, kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0 \, MW$$

Example Calculations: Options 8c and 9c



Apparent power (S):

Eq. (116) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°$$

Primary current (I_{pri}):

Eq. (117) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (118) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

Example Calculations: Options 8c and 9c

To satisfy the 115% margin in Options 8c and 9c:

Eq. (119) $I_{\sec limit} > I_{sec} \times 115\%$

$$I_{\sec limit} > 5.758\ A \times 1.15$$

$$I_{\sec limit} > 6.622\ A$$

Example Calculations: Option10

This represents the calculation for three asynchronous generators (including inverter-based installations) applying a phase distance relay (21) – directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (120) $P = 3 \times GEN_{Asych\_nameplate} \times pf$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (121) $Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (122) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (123) $S = P + jQ$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Example Calculations: Option10

Primary impedance (Z_{pri}):

Eq. (124) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 3.644\ \angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (125) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times 5$$

$$Z_{sec} = 18.22\ \angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 10:

Eq. (126) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{18.22\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 14.02\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (127) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{14.02\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{14.02\ \Omega}{0.6972}$$

$$Z_{max} < \ 20.11\angle 85.0°\ \Omega$$

Example Calculations: Options 11 and 12

Option 11 represents the calculation for a GSU transformer applying a phase time overcurrent (51) relay connected to three asynchronous generators. Similarly, these calculations can be applied to Option 12 for a phase directional time overcurrent relay (67) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (128) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (129) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (130) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (131) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\ \angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (132) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6 \angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473 \angle -39.2°\ A$$

Example Calculations: Options 11 and 12

Secondary current (I_{sec}):

Eq. (133) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Options 11 and12:

Eq. (134) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.473\angle -39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.515\angle -39.2°\ A$$

Example Calculations: Options 13a and 13b

Option 13a for the UAT assumes that the maximum nameplate rating of the winding utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner.

Primary current (I_{pri}):

Eq. (135) $$I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{UAT}}$$

$$I_{pri} = \frac{60\ MVA}{1.73 \times 13.8\ kV}$$

$$I_{pri} = 2510.2\ A$$

Secondary current (I_{sec}):

Eq. (136) $$I_{sec} = \frac{I_{pri}}{CT_{UAT}}$$

$$I_{sec} = \frac{2510.2\ A}{\frac{5000}{5}}$$

$$I_{sec} = 2.51\ \text{A}$$

To satisfy the 150% margin in Options 13a:

Eq. (137) $$I_{\sec limit} > I_{sec} \times 150\%$$

Example Calculations: Options 13a and 13b

$$I_{\sec limit} > 2.51\ A \times 1.50$$

$$I_{\sec limit} > 3.77\ A$$

Example Calculations: Option 14a

Option 14a represents the calculation for a synchronous generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance (21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Real Power output (P):

Eq. (138) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (139) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.1\ Mvar$$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the high-side nominal voltage for the GSU transformer voltage (V_{nom}):

Eq. (140) $$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{gen} = 0.85 \times 345\ kV$$

$$V_{gen} = 293.25\ kV$$

Apparent power (S):

Eq. (141) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j921.1\ Mvar$$

$$S = 1157.0\angle 52.77°\ MVA$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Example Calculations: Option 14a

Primary impedance (Z_{pri}):

Eq. (142) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1157.0\angle -52.77°\ MVA}$$

$$Z_{pri} = 74.335\angle 52.77°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (143) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times 0.2$$

$$Z_{sec} = 14.867\angle 52.77°\ \Omega$$

To satisfy the 115% margin in Option 14a:

Eq. (144) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{14.867\angle 52.77°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 12.928\angle 52.77°\ \Omega$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (145) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{12.928\ \Omega}{\cos(85.0° - 52.77°)}$$

$$Z_{max} < \frac{12.928\ \Omega}{0.846}$$

$$Z_{max} < 15.283\angle 85.0°\ \Omega$$

Example Calculations: Option 14b

Option 14b represents the simulation for a synchronous generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance (21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

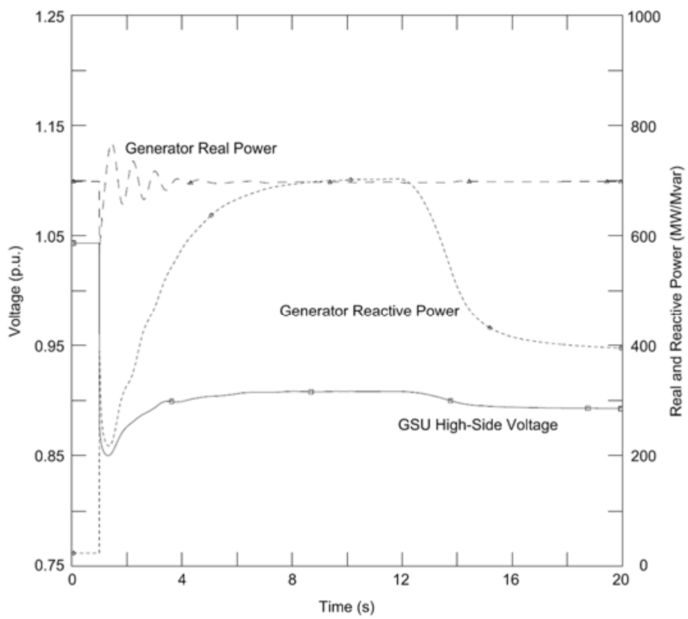
In this simulation the following values are derived:

$$Q = 703.6\ Mvar$$

$$V_{bus} = 0.908 \times V_{nom} = 313.3\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (146) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j703.6\ Mvar$$

$$S = 992.5\angle 45.1°\ MVA$$

$$\theta_{transient\ load\ angle} = 45.1°$$

Example Calculations: Option 14b

Primary impedance (Z_{pri}):

Eq. (147) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(313.3\ kV)^2}{992.5\angle -45.1°\ MVA}$$

$$Z_{pri} = 98.90\angle 45.1°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (148) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 98.90\angle 45.1°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 98.90\angle 45.1°\ \Omega \times 0.2$$

$$Z_{sec} = 19.78\angle 45.1°\ \Omega$$

To satisfy the 115% margin in Option 14b:

Eq. (149) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{19.78\angle 45.1°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 17.20\angle 45.1°\ \Omega$$

$$\theta_{transient\ load\ angle} = 45.1°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (150) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{17.20\ \Omega}{\cos(85.0° - 45.1°)}$$

$$Z_{max} < \frac{17.20\ \Omega}{0.767}$$

$$Z_{max} < 22.42\angle 85.0°\ \Omega$$

Example Calculations: Options 15a and 16a

Options 15a and 16a represent the calculation for a synchronous generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Option 15a represents applying a phase time overcurrent relay (51) or Phase overcurrent supervisory elements (50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – installed on the high-side of the GSU transformer. Option 16a represents applying a phase directional time overcurrent relay or Phase directional overcurrent supervisory elements (67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – directional toward the Transmission system– installed on the high-side of the GSU.

This example uses Option 15a as an example, where PTs and CTs are located in the high-side of the GSU transformer.

Real Power output (P):

Eq. (151) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (152) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Option 15a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the high-side nominal voltage:

Eq. (153) $$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{bus} = 0.85 \times 345\ kV$$

$$V_{bus} = 293.25\ kV$$

Apparent power (S):

Eq. (154) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (155) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

Example Calculations: Options 15a and 16a

$$I_{pri} = 2280.6\angle -52.8°\ A$$

Secondary current (I_{sec}):

Eq. (156) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{2280.6\angle -52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701\ \angle -52.8°\ A$$

To satisfy the 115% margin in Options 15a and 15b:

Eq. (157) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.701\ \angle -52.8°\ A \times 1.15$$

$$I_{\sec limit} > 6.56\ \angle -52.8°\ A$$

Example Calculations: Options 15b and 16b

Options 15b and 16b represent the calculation for a synchronous generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Option 15b represents applying a phase time overcurrent relay (51) or Phase overcurrent supervisory elements (50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – installed on the high-side of the GSU transformer. Option 16b represents applying a phase directional time overcurrent relay or Phase directional overcurrent supervisory elements (67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – directional toward the Transmission system– installed on the high-side of the GSU.

This example uses Option 15b as a simulation example, where PTs and CTs are located in the high-side of the GSU transformer.

The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

In this simulation the following values are derived:

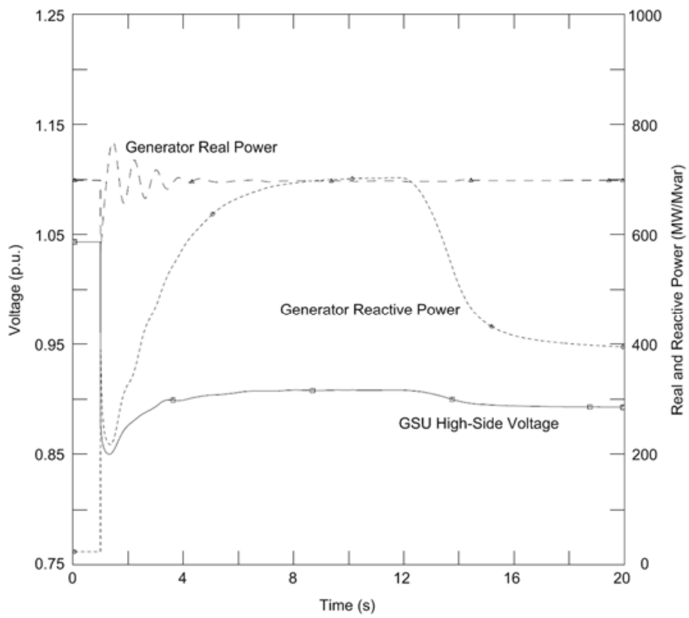
$$Q = 703.6\ Mvar$$

$$V_{bus} = 0.908 \times V_{nom} = 313.3\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

Example Calculations: Options 15b and 16b

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (158) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j703.6\ Mvar$$

$$S = 992.5\angle 45.1°\ MVA$$

Primary current (I_{pri}):

Eq. (159) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{992.5\angle -45.1°\ MVA}{1.73 \times 313.3\ kV}$$

$$I_{pri} = 1831.2\angle -45.1°\ A$$

Secondary current (I_{sec}):

Eq. (160) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{1831.2\angle -45.1°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 4.578\angle -45.1°\ A$$

Example Calculations: Options 15b and 16b

To satisfy the 115% margin in Options 15b and 16b:

Eq. (161) $I_{\sec limit} > I_{sec} \times 115\%$

$$I_{\sec limit} > 4.578 \angle -45.1° A \times 1.15$$

$$I_{\sec limit} > 5.265 \angle -45.1° A$$

Example Calculations: Option 17

Option 17 represents the calculation for three asynchronous generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance relay (21) - directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (162) $P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q):

Eq. (163) $Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Option 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the bus voltage (V_{bus}):

Eq. (164) $V_{bus} = 1.0\ p.u. \times V_{nom}$

$$V_{gen} = 1.0 \times 345\ kV$$

$$V_{gen} = 345.0\ kV$$

Apparent power (S):

Eq. (165) $S = P + jQ$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Example Calculations: Option 17

Primary impedance (Z_{pri}):

Eq. (166) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(345.0\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 904.4\angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (167) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times \frac{\frac{300}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times 0.03$$

$$Z_{sec} = 27.13\angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 17:

Eq. (168) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{27.13\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 20.869\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, and then the maximum allowable impedance reach is:

Eq. (169) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{20.869\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{20.869\ \Omega}{0.697}$$

$$Z_{max} < 29.941\angle 85.0°\ \Omega$$

Example Calculations: Options 18 and 19

Option 18 represents the calculation for three generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase time overcurrent (51) relay connected to three asynchronous generators. Similarly, Option 19 may also be applied here for the phase directional time overcurrent relays (67) directional toward the Transmission system for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (170) $P = 3 \times GEN_{Asych\_nameplate} \times pf$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (171) $Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 18 and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage (V_{bus}):

Eq. (172) $V_{nom} = 1.0\ p.u. \times V_{nom}$

$$V_{bus} = 1.0 \times 345\ kV$$

$$V_{bus} = 345\ kV$$

Apparent power (S):

Eq. (173) $S = P + jQ$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (174) $I_{pri} = \dfrac{S^*}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 345\ kV}$$

$$I_{pri} = 220.5\angle -39.2° A$$

Example Calculations: Options 18 and 19

Secondary current (I_{sec}):

Eq. (175) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio\_hv}}$$

$$I_{sec} = \frac{220.5\angle -39.2°\,A}{\frac{300}{5}}$$

$$I_{sec} = 3.675\angle -39.2°\,A$$

To satisfy the 130% margin in Options 18 and 19:

Eq. (176) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.675\angle -39.2°\,A \times 1.30$$

$$I_{\sec limit} > 4.778\angle -39.2°\,A$$

End of calculations

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 R1:

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, "while maintaining reliable fault protection" in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Unofficial Nomination Form

Updated December 7, 2016

Project 2016-04 Modifications to PRC-025-1
Standards Authorization Request (SAR) Drafting Team

Do not use this form for submitting nominations. Use the electronic form to submit nominations by **8 p.m. Eastern, Monday, December 19, 2016.** This unofficial version is provided to assist SAR drafting team nominees in compiling the information necessary to submit the electronic form.

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Scott Barfield-McGinnis (via email), or at 404-446-9689.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls.

Previous drafting or review team experience is beneficial, but not required. A brief description of the project background, expected time commitment, and other pertinent information is included below.

Background

The purpose of this project is to revise the standard to improve flexibility in applying various options and provide clarification to other issues raised in the SAR. Reliability Standard PRC-025-1 (Generator Relay Loadability), which was approved by the Federal Energy Regulatory Commission in Order No. 799 issued on July 17, 2014, became effective on October 1, 2014. Under the phased implementation plan, applicable entities have between five and seven years to become compliant with the standard depending on the scope of work required by the Generator Owner. In the course of implementing the standard, issues have been identified for specific Facility applications and load-responsive protective relays.

Standards affected: PRC-025-1

The time commitment for this project is expected to be two to three conference calls in late January 2017. Generator Owners in all regions with a background in protection systems should consider nominating. The area of focus will be wind/solar protection system requirements and protection systems for plants (synchronous & asynchronous) that are remote to transmission (+20 miles) where the line impedance may have an impact on the settings prescribed by the standard. Individuals appointed to the SAR team will be encouraged to nominate for the subsequent standard drafting team.

Name:	
Organization:	
Address:	
Telephone:	
E-mail:	

Please briefly describe your experience and qualifications to serve on the requested SAR Drafting Team (Bio):
If you are currently a member of any NERC drafting team, please list each team here: ☐ Not currently on any active SAR or standard drafting team. ☐ Currently a member of the following SAR or standard drafting team(s):
If you previously worked on any NERC drafting team please identify the team(s): ☐ No prior NERC SAR or standard drafting team. ☐ Prior experience on the following team(s):

Select each NERC Region in which you have experience relevant to the Project for which you are volunteering:		
☐ Texas RE	☐ NPCC	☐ SPP RE
☐ FRCC	☐ RF	☐ WECC
☐ MRO	☐ SERC	☐ NA – Not Applicable

Select each Industry Segment that you represent:	
☐	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, and Provincial Regulatory or other Government Entities
☐	10 — Regional Reliability Organizations and Regional Entities
☐	NA – Not Applicable

Select each Function[1] in which you have current or prior expertise:	
☐ Balancing Authority	☐ Transmission Operator
☐ Compliance Enforcement Authority	☐ Transmission Owner
☐ Distribution Provider	☐ Transmission Planner
☐ Generator Operator	☐ Transmission Service Provider
☐ Generator Owner	☐ Purchasing-selling Entity
☐ Interchange Authority	☐ Reliability Coordinator
☐ Load-serving Entity	☐ Reliability Assurer
☐ Market Operator	☐ Resource Planner
☐ Planning Coordinator	

[1] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:			
Name:		Telephone:	
Organization:		E-mail:	
Name:		Telephone:	
Organization:		E-mail:	
Provide the name and contact information of your immediate supervisor or a member of your management who can confirm your organization's willingness to support your active participation.			
Name:		Telephone:	
Title:		Email:	

Standards Announcement

Updated December 7, 2016

Project 2016-04 Modifications to PRC-025-1

Supplemental SAR Drafting Team Nomination Period Open through December 19, 2016

Now Available

Nominations are being sought for additional SAR drafting team members through **8 p.m. Eastern, Monday, December 19, 2016**.

Use the electronic form to submit a nomination. If you experience any difficulties in using the electronic form, contact Wendy Muller. An unofficial Word version of the nomination form is posted on the Standard Drafting Team Vacancies page and the project page.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in the SDT meetings. If appointed by the Standards Committee (SC), you are expected to attend most of the face-to-face meetings as well as participate in meetings held via conference calls.

The time commitment for this project is expected to be two to three conference calls in late January 2017. Generator Owners in all regions with a background in protection systems should consider nominating. The area of focus will be wind/solar protection system requirements and protection systems for plants (synchronous & asynchronous) that are remote to transmission (+20 miles) where the line impedance may have an impact on the settings prescribed by the standard. Individuals appointed to the SAR team will be encouraged to nominate for the subsequent standard drafting team.

Next Steps

The SC is expected to appoint members to the team early 2017. Nominees will be notified shortly after they have been appointed.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Scott Barfield-McGinnis (via email), or at (404) 446-9689.

A. Introduction

1. **Title:** Voltage and Reactive Control
2. **Number:** VAR-001-4.1
3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.
4. **Applicability:**
   - **4.1.** Transmission Operators
   - **4.2.** Generator Operators within the Western Interconnection (for the WECC Variance)
5. **Effective Date:**
   - **5.1.** The standard shall become effective on the first day of the first calendar quarter 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.

B. Requirements and Measures

R1. Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. *[Violation Risk Factor: High] [Time Horizon: Operational Planning]*

1.1. Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

M1. The Transmission Operator shall have evidence that it specified system voltage schedules using either a range or a target value with an associated tolerance band.

For part 1.1, the Transmission Operator shall have evidence that the voltage schedules (which is either a range or a target value with an associated tolerance band) were provided to its Reliability Coordinator and adjacent Transmission Operators within 30 days of a request. Evidence may include, but is not limited to, emails, website postings, and meeting minutes.

R2. Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operational Planning]*

M2. Each Transmission Operator shall have evidence of scheduling sufficient reactive resources based on their assessments of the system. For the operational planning time horizon, Transmission Operators shall have evidence of assessments used as the basis for how resources were scheduled.

R3. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operational Planning]*

M3. Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as necessary in Real-time. This may include instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

R4. The Transmission Operator shall specify the criteria that will exempt generators from: 1) following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any associated notifications. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

4.1 If a Transmission Operator determines that a generator has satisfied the exemption criteria, it shall notify the associated Generator Operator.

M4. Each Transmission Operator shall have evidence of the documented criteria for generator exemptions.

For part 4.1, the Transmission Operator shall also have evidence to show that, for each generator in its area that is exempt from: 1) following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any notifications, the associated Generator Operator was notified of this exemption.

R5. Each Transmission Operator shall specify a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) at either the high voltage side or low voltage side of the generator step-up transformer at the Transmission Operator's discretion. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The Transmission Operator shall provide the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage).

5.2. The Transmission Operator shall provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

5.3. The Transmission Operator shall provide the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the Generator Operator within 30 days of receiving a request.

M5. The Transmission Operator shall have evidence of a documented voltage or Reactive Power Schedule (which is either a range or a target value with an associated tolerance band).

For part 5.1, the Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the applicable Generator Operators, and that the Generator Operator was directed to comply with the schedule in automatic voltage control mode, unless exempted.

For part 5.2, the Transmission Operator shall have evidence it provided notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band). For part 5.3, the Transmission Operator shall have evidence it provided the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) within 30 days of receiving a request by a Generator Operator.

R6. After consultation with the Generator Owner regarding necessary step-up transformer tap changes and the implementation schedule, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with the requirement and that it consulted with the Generator Owner.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" refers to 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 a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Operator shall retain evidence for Measures 1 through 6 for 12 months. The Compliance Monitor shall retain any audit data for three years.

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	**Operational Planning**	**High**	N/A	N/A	N/A	The Transmission Operator does not specify a system voltage schedule (which is either a range or a target value with an associated tolerance band).
R2	**Real-time Operations, Same-day Operations, and Operational Planning**	**High**	N/A	N/A	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an SOL.	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an IROL.
R3	**Real-time Operations, Same-day Operations, and Operational Planning**	**High**	N/A	N/A	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an SOL.	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an IROL.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	**Operations Planning**	**Lower**	N/A	N/A	The Transmission Operator has exemption criteria and notified the Generator Operator, but the Transmission Operator does not have evidence of the notification to the Generator Operator.	The Transmission Operator does not have exemption criteria.
R5	**Operations Planning**	**Medium**	N/A	The Transmission Operator does not provide the criteria for voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) after 30 days of a request.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to all Generator Operators.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to any Generator Operators. Or The Transmission Operator does not provide the Generator Operator with the notification requirements for deviations from the

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).
R6	**Operations Planning**	**Lower**	The Transmission Operator does not provide either the technical justification or timeframe for changing generator step-up tap settings.	N/A	N/A	The Transmission Operator does not provide the technical justification and the timeframe for changing generator step-up tap settings.

D. Regional Variances

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R4 and R5. Please note that Requirement R4 is deleted and R5 is replaced with the following requirements.

Requirements

E.A.13 Each Transmission Operator shall issue any one of the following types of voltage schedules to the Generator Operators for each of their generation resources that are on-line and part of the Bulk Electric System within the Transmission Operator Area: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- A voltage set point with a voltage tolerance band and a specified period.
- An initial volt-ampere reactive output or initial power factor output with a voltage tolerance band for a specified period that the Generator Operator uses to establish a generator bus voltage set point.
- A voltage band for a specified period.

E.A.14 Each Transmission Operator shall provide one of the following voltage schedule reference points for each generation resource in its Area to the Generator Operator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- The generator terminals.
- The high side of the generator step-up transformer.
- The point of interconnection.
- A location designated by mutual agreement between the Transmission Operator and Generator Operator.

E.A.15 Each Generator Operator shall convert each voltage schedule specified in Requirement E.A.13 into the voltage set point for the generator excitation system. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

E.A.16 Each Generator Operator shall provide its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals within 30 calendar days of request by its Transmission Operator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

E.A.17 Each Transmission Operator shall provide to the Generator Operator, within 30 calendar days of a request for data by the Generator Operator, its transmission equipment data and operating data that supports development of the voltage set point conversion methodology. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

E.A.18 Each Generator Operator shall meet the following control loop specifications if the Generator Operator uses control loops external to the Automatic Voltage Regulators (AVR) to manage MVar loading: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

E.A.18.1. Each control loop's design incorporates the AVR's automatic voltage controlled response to voltage deviations during System Disturbances.

E.A.18.2. Each control loop is only used by mutual agreement between the Generator Operator and the Transmission Operator affected by the control loop.

Measures[1]

M.E.A.13 Each Transmission Operator shall have and provide upon request, evidence that it provided the voltage schedules to the Generator Operator. Dated spreadsheets, reports, voice recordings, or other documentation containing the voltage schedule including set points, tolerance bands, and specified periods as required in Requirement E.A.13 are acceptable as evidence.

M.E.A.14 The Transmission Operator shall have and provide upon request, evidence that it provided one of the voltage schedule reference points in Requirement E.A.14 for each generation resource in its Area to the Generator Operator. Dated letters, e-mail, or other documentation that contains notification to the Generator Operator of the voltage schedule reference point for each generation resource are acceptable as evidence.

M.E.A.15 Each Generator Operator shall have and provide upon request, evidence that it converted a voltage schedule as described in Requirement E.A.13 into a voltage set point for the AVR. Dated spreadsheets, logs, reports, or other documentation are acceptable as evidence.

M.E.A.16 The Generator Operator shall have and provide upon request, evidence that within 30 calendar days of request by its Transmission Operator it provided its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals. Dated reports, spreadsheets, or other documentation are acceptable as evidence.

M.E.A.17 The Transmission Operator shall have and provide upon request, evidence that within 30 calendar days of request by its Generator Operator it provided data to support development of the voltage set point conversion methodology. Dated reports, spreadsheets, or other documentation are acceptable as evidence.

M.E.A.18 If the Generator Operator uses outside control loops to manage MVar loading, the Generator Operator shall have and provide upon request, evidence that it met the control loop specifications in sub-parts E.A.18.1 through E.A.18.2. Design specifications with identified agreed-upon control loops, system reports, or other dated documentation are acceptable as evidence.

[1] The number for each measure corresponds with the number for each requirement, i.e. M.E.A.13 means the measure for Requirement E.A.13.

Violation Severity Levels

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.13	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to at least one generation resource but less than or equal to 5% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 5% but less than or equal to 10% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 10% but less than or equal to 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.
E.A.14	The Transmission Operator did not provide a voltage schedule reference point for at least one but less than or equal to 5% of the generation resources in the Transmission Operator area.	The Transmission Operator did not provide a voltage schedule reference point for more than 5% but less than or equal to 10% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not a voltage schedule reference point for more than 10% but less than or equal to 15% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not provide a voltage schedule reference point for more than 15% of the generation resources in the Transmission Operator Area.
E.A.15	The Generator Operator failed to convert at least one voltage schedule in Requirement E.A.13 into the voltage set point for the AVR for less	The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 25% or more but	The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 50% or more but less than 75% of	The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 75% or more of the voltage schedules.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	than 25% of the voltage schedules.	less than 50% of the voltage schedules.	the voltage schedules.	
E.A.16	The Generator Operator provided its voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Transmission Operator.	The Generator Operator did not provide its voltage set point conversion methodology within 120 days of a request by the Transmission Operator.
E.A.17	The Transmission Operator provided its data to support development of the voltage set point conversion methodology than 30 days but less than or equal to 60 days of a request by the Generator Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Generator. Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Generator. Operator.	The Transmission Operator did not provide its data to support development of the voltage set point conversion methodology within 120 days of a request by the Generator Operator.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.18	N/A	The Generator Operator did not meet the control loop specifications in EA18.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in EA18.1 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in EA18.1 through EA18.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

For technical basis for each requirement, please review the rationale provided for each requirement.

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 R1:

Paragraph 1868 of Order No. 693 requires NERC to add more "detailed and definitive requirements on “established limits” and “sufficient reactive resources”, and identify acceptable margins (i.e. voltage and/or reactive power margins)." Since Order No. 693 was issued, however, several FAC and TOP standards have become enforceable to add more requirements around voltage limits. More specifically, FAC-011 and FAC-014 require that System Operating Limits (SOLs) and reliability margins are established. The NERC Glossary definition of SOLs includes both: 1) Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) and 2*)* System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits). Therefore, for reliability reasons Requirement R1 now requires a Transmission Operator (TOP) to set voltage or Reactive Power schedules with associated tolerance bands. Further, since neighboring areas can affect each other greatly, each TOP must also provide a copy of these schedules to its Reliability Coordinator (RC) and adjacent TOP upon request.

Rationale for R2:

Paragraph 1875 from Order No. 693 directed NERC to include requirements to run voltage stability analysis periodically, using online techniques where commercially available and offline tools when online tools are not available. This standard does not explicitly require the periodic voltage stability analysis because such analysis would be performed pursuant to the SOL methodology developed under the FAC standards. TOP standards also require the TOP to operate within SOLs and Interconnection Reliability Operating Limits (IROL). The VAR standard drafting team (SDT) and industry participants also concluded that the best models and tools are the ones that have been proven and the standard should not add a requirement for a responsible entity to purchase new online simulations tools. Thus, the VAR SDT simplified the requirements to ensuring sufficient reactive resources are online or scheduled. Controllable load is specifically included to answer FERC's directive in Order No. 693 at Paragraph 1879.

Rationale for R3:

Similar to Requirement R2, the VAR SDT determined that for reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL.

Rationale for R4:

The VAR SDT received significant feedback on instances when a TOP would need the flexibility for defining exemptions for generators. These exemptions can be tailored as the TOP deems necessary for the specific area's needs. The goal of this requirement is to provide a TOP the ability to exempt a Generator Operator (GOP) from: 1) a voltage or Reactive Power schedule, 2) a setting on the AVR, or 3) any VAR-002 notifications based on the TOP's criteria. Feedback from the industry detailed many system events that would require these types of exemptions which included, but are not limited to: 1) maintenance during shoulder months, 2) scenarios where two units are located within close proximity and both cannot be in voltage control mode, and 3) large system voltage swings where it would harm reliability if all GOP were to notify their respective TOP of deviations at one time. Also, in an effort to improve the requirement, the sub-requirements containing an exemption list were removed from the currently enforceable standard because this created more compliance issues with regard to how often the list would be updated and maintained.

Rationale for R5:

The new requirement provides transparency regarding the criteria used by the TOP to establish the voltage schedule. This requirement also provides a vehicle for the TOP to use appropriate granularity when setting notification requirements for deviation from the voltage or Reactive Power schedule. Additionally, this requirement provides clarity regarding a "tolerance band" as specified in the voltage schedule and the control dead-band in the generator's excitation system.

Voltage Schedule tolerances are the bandwidth that accompanies the voltage target in a voltage schedule, should reflect the anticipated fluctuation in voltage at the Generation Operator's facility during normal operations, and be based on the TOP's assessment of N-1 and credible N-2 system contingencies. The voltage schedule's bandwidth should not be confused with the control dead-band that is programmed into a Generation Operator's automatic voltage regulator's control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.

Rationale for R6:

Although tap settings are first established prior to interconnection, this requirement could not be deleted because no other standard addresses when a tap setting must be adjusted. If the tap setting is not properly set, then the amount of VARs produced by a unit can be affected.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	June 18, 2007	FERC approved Version 1 of the standard.	Revised
1	July 3, 2007	Added “Generator Owners” and “Generator Operators” to Applicability section.	Errata
1	August 23, 2007	Removed “Generator Owners” and “Generator Operators” to Applicability section.	Errata
2	August 5, 2010	Adopted by NERC Board of Trustees; Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.	Revised
2	January, 10 2011	FERC issued letter order approving the addition of LSEs and Controllable Load to the standard.	Revised
3	May 9, 2012	Adopted by NERC Board of Trustees; Modified to add a WECC region variance	Revised
3	June 20, 2013	FERC issued order approving VAR-001-3	Revised
3	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	Revised
4	February 6, 2014	Adopted by NERC Board of Trustees	Revised
4	August 1, 2014	FERC issued letter order issued approving VAR-001-4	
4.1	August 25, 2015	Added “or” to Requirement R5, 5.3 to read: schedules or Reactive Power	Errata
4.1	November 13, 2015	FERC Letter Order approved errata to VAR-001-4.1. Docket RD15-6-000	Errata

A. Introduction

1. **Title:** **Generator Operation for Maintaining Network Voltage Schedules**
2. **Number:** VAR-002-4
3. **Purpose:** To ensure generators provide reactive support and voltage control, within generating Facility capabilities, in order to protect equipment and maintain reliable operation of the Interconnection.
4. **Applicability:**
   4.1. Generator Operator
   4.2. Generator Owner
5. **Effective Dates**

   See Implementation Plan.

B. Requirements and Measures

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (with its automatic voltage regulator (AVR) in service and controlling voltage) or in a different control mode as instructed by the Transmission Operator unless: 1) the generator is exempted by the Transmission Operator, or 2) the Generator Operator has notified the Transmission Operator of one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- That the generator is being operated in start-up,[1] shutdown,[2] or testing mode pursuant to a Real-time communication or a procedure that was previously provided to the Transmission Operator; or
- 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.

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode or in a different control mode as specified in Requirement R1. If a generator is being started up or shut down with the automatic voltage control off, or is being tested, and no notification of the AVR status is made to the Transmission Operator, the Generator Operator will have evidence that it notified the Transmission Operator of its procedure for placing the unit into automatic voltage control mode as required in Requirement R1. Such evidence may include, but is not limited to, dated evidence of transmittal of the procedure such as an electronic message or a transmittal letter with the procedure included or attached. If a generator is exempted, the Generator Operator shall also have evidence that the generator is exempted from being in automatic voltage control mode (with its AVR in service and controlling voltage).

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule[3] (within each generating Facility's capabilities[4]) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. When a generator's AVR is out of service or the generator does not have an AVR, the Generator Operator shall use an alternative method to control the generator reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

2.2. When instructed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

2.3. Generator Operators that do not monitor the voltage at the location specified in their voltage schedule shall have a methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

M2. In order to identify when a generator is deviating from its schedule, the Generator Operator will monitor voltage based on existing equipment at its Facility. The Generator Operator shall have evidence to show that the generator maintained the voltage or Reactive Power schedule provided by the Transmission Operator, or shall have evidence of meeting the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. Evidence may include, but is not limited to, operator logs, SCADA data, phone logs, and any other notifications that would alert the Transmission Operator or otherwise demonstrate that the Generator Operator complied with the Transmission Operator's instructions for addressing deviations from the voltage or Reactive Power schedule.

For Part 2.1, when a generator's AVR is out of service or the generator does not have an AVR, a Generator Operator shall have evidence to show an alternative method was used to control the generator reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

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[1] Start-up is deemed to have ended when the generator is ramped up to its minimum continuously sustainable load and the generator is prepared for continuous operation.
[2] Shutdown is deemed to begin when the generator is ramped down to its minimum continuously sustainable load and the generator is prepared to go offline.
[3] The voltage or Reactive Power schedule is a target value with a tolerance band or a voltage or Reactive Power range communicated by the Transmission Operator to the Generator Operator.
[4] Generating Facility capability may be established by test or other means, and may not be sufficient at times to pull the system voltage within the schedule tolerance band. Also, when a generator is operating in manual control, reactive power capability may change based on stability considerations.

For Part 2.2, the Generator Operator shall have evidence that it complied with the Transmission Operator's instructions to modify its voltage or provided an explanation to the Transmission Operator of why the Generator Operator was unable to comply with the instruction. Evidence may include, but is not limited to, operator logs, SCADA data, and phone logs.

For Part 2.3, for Generator Operators that do not monitor the voltage at the location specified on the voltage schedule, the Generator Operator shall demonstrate the methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

R3. Each Generator Operator shall notify its associated Transmission Operator of a status change on the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change. If the status has been restored within 30 minutes of such change, then the Generator Operator is not required to notify the Transmission Operator of the status change *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any status change identified in Requirement R3. If the status has been restored within the first 30 minutes, no notification is necessary.

R4. Each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability due to factors other than a status change described in Requirement R3. If the capability has been restored within 30 minutes of the Generator Operator becoming aware of such change, then the Generator Operator is not required to notify the Transmission Operator of the change in reactive capability. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- Reporting of status or capability changes as stated in Requirement R4 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability in accordance with Requirement R4. If the capability has been restored within the first 30 minutes, no notification is necessary.

R5. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

5.1. For generator step-up and auxiliary transformers[5] with primary voltages equal to or greater than the generator terminal voltage:

5.1.1. Tap settings.

5.1.2. Available fixed tap ranges.

5.1.3. Impedance data.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up and auxiliary transformers as required in Requirement R5, Part 5.1.1 through Part 5.1.3 within 30 calendar days.

R6. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

6.1. If the Generator Owner cannot comply with the Transmission Operator's specifications, the Generator Owner shall notify the Transmission Operator and shall provide the technical justification.

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation in accordance with Requirement R6. The Generator Owner shall have evidence that it notified its associated Transmission Operator when it could not comply with the Transmission Operator's step-up transformer tap specifications in accordance with Requirement R6, Part 6.1.

[5] For dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies only to those transformers that have at least one winding at a voltage of 100 kV or above.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" refers to 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 Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. The Generator Operator shall maintain all other evidence for the current and previous calendar year.

The Compliance Monitor shall retain any audit data for three years.

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	**Real-time Operations**	**Medium**	N/A	N/A	N/A	Unless exempted, the Generator Operator did not operate each generator connected to the interconnected transmission system in the automatic voltage control mode or in a different control mode as instructed by the Transmission Operator, and failed to provide the required notifications to Transmission Operator as identified in Requirement R1.
R2	**Real-time Operations**	**Medium**	N/A	N/A	The Generator Operator did not have a conversion methodology when it monitors voltage at a location different from the schedule provided by the Transmission Operator.	The Generator Operator did not maintain the voltage or Reactive Power schedule as instructed by the Transmission Operator and did not make the necessary notifications required by the Transmission Operator. OR The Generator Operator did not have an operating AVR, and the responsible entity did not use an alternative method for controlling voltage. OR The Generator Operator did not modify voltage when directed, and the

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						responsible entity did not provide any explanation.
R3	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of the status change.
R4	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of becoming aware of the capability change.
R5	**Real-time Operations**	**Lower**	N/A	N/A	The Generator Owner failed to provide its associated Transmission Operator and Transmission Planner one of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.	The Generator Owner failed to provide to its associated Transmission Operator and Transmission Planner two or more of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.
R6	**Real-time Operations**	**Lower**	N/A	N/A	N/A	The Generator Owner did not ensure the tap changes were made according the Transmission Operator’s specifications.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Generator Owner failed to perform the tap changes, and the Generator Owner did not provide technical justification for why it could not comply with the Transmission Operator specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	5/1/2006	Added "(R2)" to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006
1a	12/19/2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007	Revised
1a	1/16/2007	In Section A.2., Added "a" to end of standard number. Section F: added "1."; and added date.	Errata
1.1a	10/29/2008	BOT adopted errata changes; updated version number to "1.1a"	Errata
1.1b	3/3/2009	Added Appendix 2 – Interpretation of VAR-002-1.1a approved by BOT on February 10, 2009	Revised
2b	4/16/2013	Revised R1 to address an Interpretation Request. Also added previously approved VRFs, Time Horizons and VSLs. Revised R2 to address consistency issue with VAR-001-2, R4. FERC Order issued approving VAR-002-2b.	Revised
3	5/5/2014	Revised under Project 2013-04 to address outstanding Order 693 directives.	Revised
3	5/7/2014	Adopted by NERC Board of Trustees	
3	8/1/2014	Approved by FERC in docket RD14-11-000	
4	8/27/2014	Revised under Project 2014-01 to clarify applicability of Requirements to BES dispersed power producing resources.	Revised

4	11/13/2014	Adopted by NERC Board of Trustees	
4	5/29/2015	FERC Letter Order in Docket No. RD15-3-000 approving VAR-002-4	

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 R1:

This requirement has been maintained due to the importance of running a unit with its automatic voltage regulator (AVR) in service and in either voltage controlling mode or the mode instructed by the TOP. However, the requirement has been modified to allow for testing, and the measure has been updated to include some of the evidence that can be used for compliance purposes.

Rationale for R2:

Requirement R2 details how a Generator Operator (GOP) operates its generator(s) to provide voltage support and when the GOP is expected to notify the Transmission Operator (TOP). In an effort to remove prescriptive notification requirements for the entire continent, the VAR-002-3 standard drafting team (SDT) opted to allow each TOP to determine the notification requirements for each of its respective GOPs based on system requirements. Additionally, a new Part 2.3 has been added to detail that each GOP may monitor voltage by using its existing facility equipment.

Conversion Methodology: There are many ways to convert the voltage schedule from one voltage level to another. Some entities may choose to develop voltage regulation curves for their transformers; others may choose to do a straight ratio conversion; others may choose an entirely different methodology. All of these methods have technical challenges, but the studies performed by the TOP, which consider N-1 and credible N-2 contingencies, should compensate for the error introduced by these methodologies, and the TOP possesses the authority to direct the GOP to modify its output if its performance is not satisfactory. During a significant system event, such as a voltage collapse, even a generation unit in automatic voltage control that controls based on the low-side of the generator step-up transformer should see the event on the low-side of the generator step-up transformer and respond accordingly.

Voltage Schedule Tolerances: The bandwidth that accompanies the voltage target in a voltage schedule should reflect the anticipated fluctuation in voltage at the GOP's Facility during normal operations and be based on the TOP's assessment of N-1 and credible N-2 system contingencies. The voltage schedule's bandwidth should not be confused with the control dead-band that is programmed into a GOP's AVR control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.

Rationale for R3:

This requirement has been modified to limit the notifications required when an AVR goes out of service and quickly comes back in service. Notifications of this type of status change provide little to no benefit to reliability. Thirty (30) minutes have been built into the requirement to allow a GOP time to resolve an issue before having to notify the TOP of a status change. The requirement has also been amended to remove the sub-requirement to provide an estimate for the expected duration of the status change.

Rationale for R4:

This requirement has been bifurcated from the prior version VAR-002-2b Requirement R3. This requirement allows GOPs to report reactive capability changes after they are made aware of the change. The current standard requires notification as soon as the change occurs, but many GOPs are not aware of a reactive capability change until it has taken place.

Rationale for Exclusion in R4:

VAR-002 addresses control and management of reactive resources and provides voltage control where it has an impact on the BES. For dispersed power producing resources as identified in Inclusion I4, Requirement R4 should not apply at the individual generator level due to the unique characteristics and small scale of individual dispersed power producing resources. In addition, other standards such as proposed TOP-003 require the Generator Operator to provide Real-time data as directed by the TOP.

Rationale for R5:

This requirement and corresponding measure have been maintained due to the importance of having accurate tap settings. If the tap setting is not properly set, then the VARs available from that unit can be affected. The prior version of VAR-002-2b, Requirement R4.1.4 (the +/- voltage range with step-change in % for load-tap changing transformers) has been removed. The percentage information was not needed because the tap settings, ranges and impedance are required. Those inputs can be used to calculate the step-change percentage if needed.

Rationale for Exclusion in R5:

The Transmission Operator and Transmission Planner only need to review tap settings, available fixed tap ranges, impedance data and the +/- voltage range with step-change in % for load-tap changing transformers on main generator step-up unit transformers which connect dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition to their transmission system. The dispersed power producing resources individual generator transformers are not intended, designed or installed to improve voltage performance at the point of interconnection. In addition, the dispersed power producing resources individual generator transformers have traditionally been excluded from Requirement R4 and R5 of VAR- 002-2b (similar requirements are R5 and R6 for VAR-002-3), as they are not used to improve voltage performance at the point of interconnection.

Rationale for R6:

This requirement and corresponding measure have been maintained due to the importance of having accurate tap settings. If the tap setting is not properly set, then the VARs available from that unit can be affected.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Processes Manual

VERSION ~~3~~ TBD

Effective: ~~June 26, 2013~~TBD

to ensure the reliability of the bulk power system

Table of Contents

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 complianc*e, 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,*

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[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.

[3] Reliability Standards shall be numbered in accordance with the NERC Standards Numbering Convention as provide on the Reliability Standards Resources web page.

Compliance Elements: Elements to aid in the administration of ERO compliance monitoring and enforcement responsibilities.[4]

- ***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.

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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.

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 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 team

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[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.

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.

STEP 1: Project Identified in Reliability Standards Development Plan or initiated by the Standards Committee

Draft SAR

STEP 2: Post SAR for 30-day Informal Comment Period

STEP 3: Develop Draft of Standard, Implementation Plan and VRFs and VSLs

Form Drafting Team	If needed, conduct Field Test of Requirements	Conduct Quality Review	Collect Informal Feedback

STEP 4: Obtain Standards Committee Approval to Post for Comment and Ballot

STEP 5: 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	Conduct Non-Binding Poll of VRFs and VSLs

If significant changes are needed to the Draft Reliability Standard then conduct Additional Ballot (Repeat Step 5)

STEP 6: Post Response to Comments

STEP 7: Conduct Final Ballot

10 day Period

STEP 8: Submit Reliability Standard and Implementation Plan to BOT for Adoption and Approval

STEP 9: Submit all BOT-approved documents to Applicable Governmental Authorities for approval

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 can be developed, the Standards Committee shall direct the NERC Reliability Standards Staff to post the

[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.

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 comment period(s) is to solicit very specific feedback on the final draft of the Reliability Standard, implementation plan and VRFs and VSLs.

[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.

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.

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[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 ~~es~~ 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. Drafting teams are not required to collect and analyze data or to conduct a field test to validate a Reliability Standard.

6.1: Field Tests and Data Analysis ~~for Validation of Concepts~~(collectively "Field Test")

1. Field ~~t~~Tests ~~or collection and analysis of data~~ to validate concepts that support the development of Requirements should be conducted before the ~~SAR~~ Standard Authorization Request ("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.~~
2. To conduct a Field Test of a technical concept in a proposed new or revised Reliability Standard, the requesting team must work with NERC staff to identify one of NERC's technical committees to lead the effort in conducting the Field Test.

6.1.1: Field Test Approval

The request to conduct a Field Test must include, at a minimum:

- the Field Test plan,
- the implementation schedule, and
- an expectation for periodic updates of the analysis of the results.

Prior to the requesting team conducting a Field Test, it must:

- first receive approval from the lead NERC technical committee, and
- subsequently receive approval from the Standards Committee.

6.1.2: Field Test Suspension

During the Field Test, if the lead NERC technical committee overseeing the Field Test determines there is a reliability risk to the BES:

- the lead NERC technical committee shall stop or modify the activity;
- the lead NERC technical committee shall inform the Standards Committee that the activity was stopped or modified;

- the Standards Committee, with the assistance of NERC staff, shall document the cessation or modification of the Field Test; and
- the Standards Committee shall notify NERC compliance staff to coordinate any compliance related issues such as continuance or cessation of waivers.

Prior to the Field Test being restarted after it has been stopped, the requesting team must resubmit the Field Test and receive approval as outlined in section 6.1.1.

If the Field Test does not provide sufficient information to formulate a conclusion within the time allotted in the plan, the Chair of the Standards Committee will work with the requesting team and the lead NERC technical committee to determine whether to continue, modify or terminate the Field Test.

If ~~a drafting team finds that it~~ the requesting team determines a need~~s~~ to ~~collect and analyze data or~~ conduct a ~~field~~ Field ~~test~~ Test of a concept that was not identified ~~when~~ in 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~~it must create a supplemental SAR to include the Field Test and receive approval as outlined in section 6.1.1.

~~**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.~~

6.~~3~~2: 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~~After approval of the Field Test, the requesting team may request waivers of compliance for Field Test participants that would be rendered ~~render Registered Entities~~ incapable of complying with the ~~current~~ Requirement(s) of ~~an approved~~the currently enforceable 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~~due to their participation. ~~Upon request, the Standards Committee shall seek approval for the waiver from t~~The Compliance Monitoring and Enforcement Program staff ~~prior to the approval of the field test or data collection and analysis~~shall determine whether to approve the requested waivers, and the Standards staff shall inform the affected registered entities. Prior to initiation of the Field Test, the Chair of the Standards Committee, in conjunction with the lead NERC technical committee chair, shall inform the

~~[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.~~

NERC Board of the pending Field Test, the expected duration, and any requested waivers from compliance for registered entities.

During the Field Test, the requesting team conducting the Field Test shall provide periodic updates (no less than quarterly) on the progress of the Field Tests to the Standards Committee and the applicable NERC technical committees. The Chair of the Standards Committee shall keep the NERC Board informed.

~~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

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STEP 2: Request for Interpretation reviewed by NERC Reliability Standards and Legal Staffs and Recommendation submitted to the Standards Committee

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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.

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STEP 4: Develop Draft of Interpretation

Conduct Quality Review	Collect Informal Feedback

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STEP 5: Obtain Standards Committee Approval to Post Interpretation for Comment and Ballot

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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.

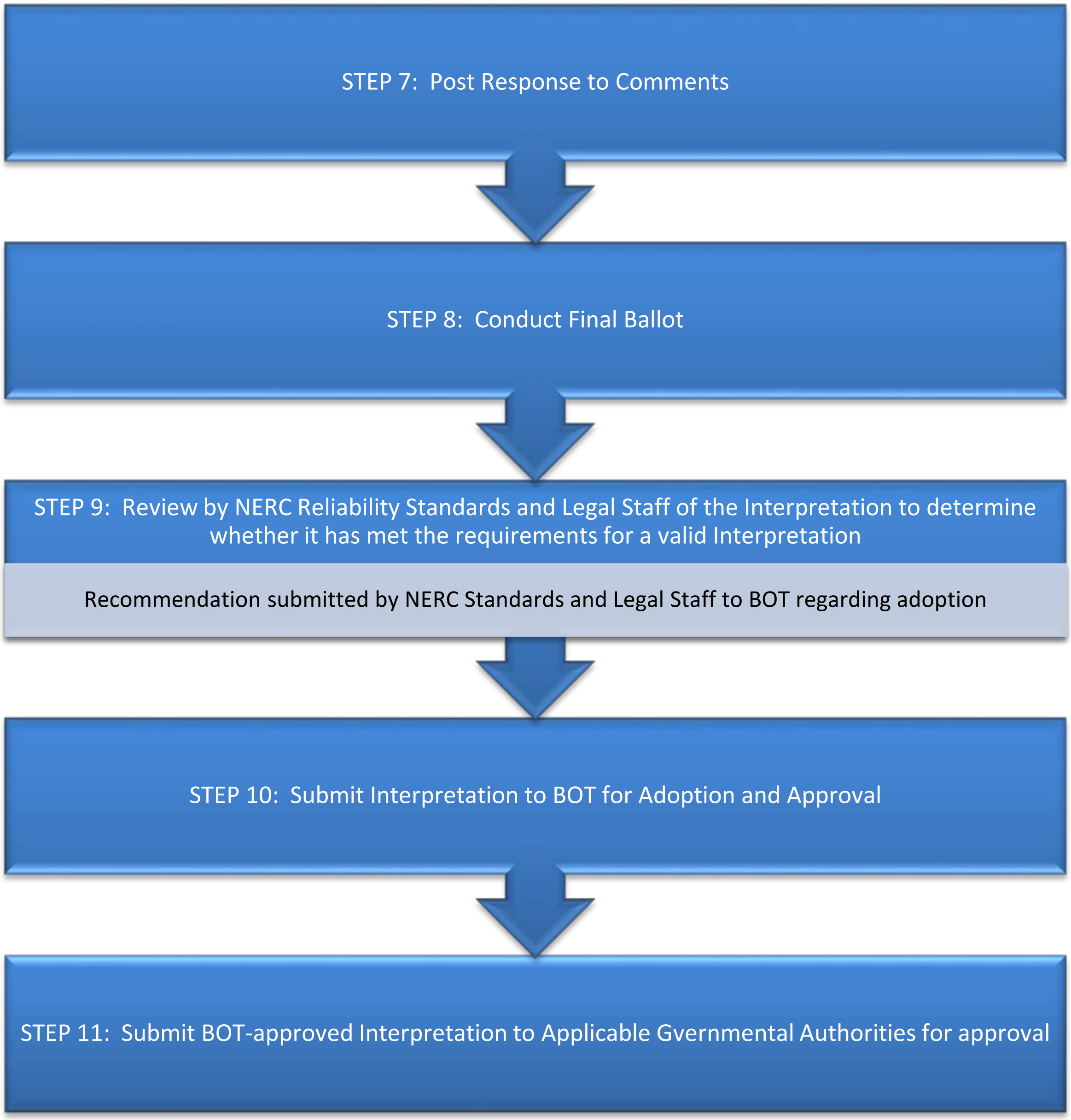

FIGURE 2: Process for Developing an Interpretation

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

[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.

Variance shall be initiated through a SAR, and processed and approved in the same 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.

10.4: Formal Stakeholder Comment & Ballot Window

[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.

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

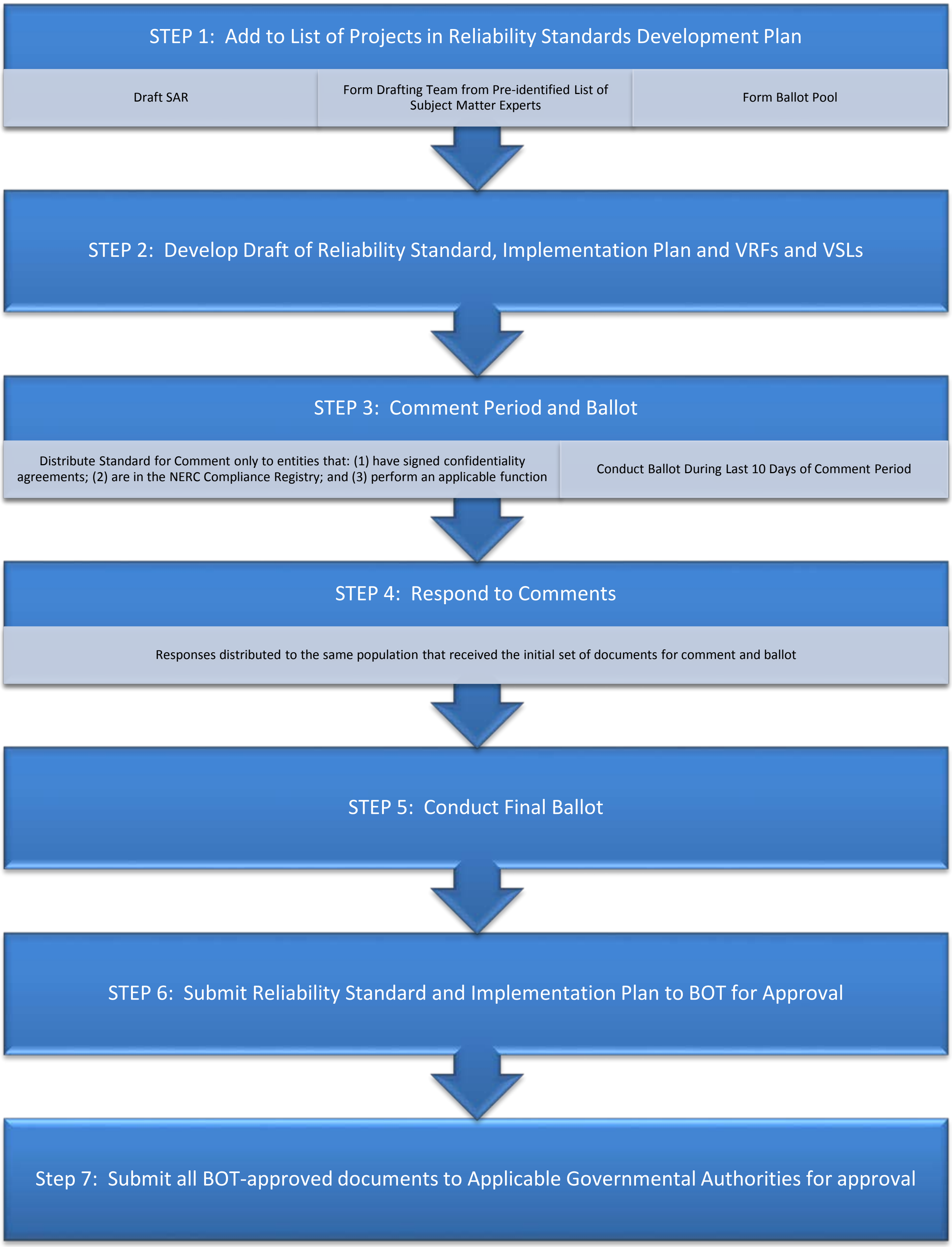

FIGURE 3: Process for Developing a Standard Responsive to an Imminent, Confidential Issue

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

STEP 1: Add to List of Projects in Reliability Standards Development Plan

Draft SAR	Form Drafting Team from Pre-identified List of Subject Matter Experts	Form Ballot Pool

STEP 2: Develop Draft of Reliability Standard, Implementation Plan and VRFs and VSLs

Conduct Quality Review

STEP 3: Obtain Standards Committee Approval to Post for Comment and Ballot

STEP 3: Formal Comment Period and Ballot
(Comment Period and Ballot Window may be abbreviated)

Distribute Standard for Comment only to entities that: (1) have signed confidentiality agreements; (2) are in the NERC Compliance Registry; and (3) perform an applicable function	Conduct Ballot During Last 10 Days of Comment Period

If significant changes are needed to the draft Reliability Standard then conduct Additional Ballot (Repeat Step 3)

STEP 4: Respond to Comments

Responses distributed to the same population that received the initial set of documents for comment and ballot

STEP 5: Conduct Final Ballot

STEP 6: Submit Reliability Standard and Implementation Plan to BOT for Approval

Step 7: Submit all BOT-approved documents to Applicable Governmental Authorities for approval

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.

New or Modified Term(s) Used in NERC Reliability Standards

Glossary Term(s):

System Operating Limits: Reliability limits used for operations, to include Facility Ratings, System voltage limits, and stability limitations. ~~The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:~~

- ~~Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)~~
- ~~transient stability ratings (applicable pre- and post- Contingency stability limits)~~
- ~~voltage stability ratings (applicable pre- and post-Contingency voltage stability)~~
- ~~system voltage limits (applicable pre- and post-Contingency voltage limits)~~

SOL Exceedance: An operating condition characterized by any of the following:

- Actual or pre-Contingency flow on a Facility is above the Normal Rating
- Calculated post-Contingency flow on a Facility is above the highest Emergency Rating
- Calculated post-Contingency flow on a Facility is above a Facility Rating for which there is not sufficient time to reduce the flow to acceptable levels should the Contingency occurs
- Actual or pre-Contingency bus voltage is outside normal System voltage limits
- Calculated post-Contingency bus voltage is outside the emergency system voltage limits
- Calculated post-Contingency bus voltage is outside emergency system voltage limits for which there is not sufficient time to relieve the condition should the Contingency occurs
- Operating parameters indicate the next Contingency could result in instability.

A. Introduction

1. **Title:** System Operating Limits Methodology for the Operations Horizon

2. **Number:** FAC-011-4

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

5. **Effective Date:** TBD

B. Requirements and Measures

R1. Each Reliability Coordinator shall have a methodology for establishing SOLs ("SOL Methodology") within its Reliability Coordinator Area.

R2. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable Facility Ratings to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.

R3. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable steady-state System voltage limits to be used in operations. The method shall:

3.1. Require that System voltage limits are not outside of the Facility voltage ratings;

3.2. Require that System voltage limits are not outside of voltage limits identified in Nuclear Plant Interface Requirements;

3.3. Require that System voltage limits are above UVLS relay settings;

3.4. Identify the lowest allowable System voltage limit;

3.5. Address the use of common System voltage limits between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area; and,

3.6. Address coordination of System voltage limits between adjacent Transmission Operators in its Reliability Coordinator Area.

R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limitations to be used in operations. The method shall:

4.1. Specify stability performance criteria for single Contingencies and for multiple Contingencies (as identified in Requirement R5), including any margins applied. The criteria shall consider the following:

4.1.1. steady-state voltage stability;

4.1.2. transient voltage response;

4.1.3. angular stability; and

4.1.4. System damping.

4.2. Require that stability limitations are established to meet the BES performance criteria specified in Part 4.1 for the following Contingencies:

4.2.1. Loss of one of the following either by single phase or three phase Fault to ground with normal clearing, or without a Fault:

- generator;
- Transmission circuit;
- transformer;
- shunt device;
- single pole of a direct current line.

4.2.2. Loss of any multiple Contingencies identified in Requirement R5.

4.3. Describe how instability risks are identified, considering realistic levels of transfers, Load and generation dispatch;

4.4. Consider the stability limitations (and corresponding multiple Contingencies) provided by the Planning Coordinator in accordance with FAC-014-3 Requirement R8;

4.5. Include a description of the study models, including the level of detail that is required and allowed uses of Remedial Action Schemes (RAS); and,

4.6. Specify how stability limitations will be established when there is an impact to more than one TOP in its Reliability Coordinator Area.

R5. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the multiple Contingencies used in the evaluation for potential System instability, Cascading outages or uncontrolled separation.

R6. Each Reliability Coordinator shall include in its SOL Methodology the method and criteria for establishing Interconnection Reliability Operating Limits (IROLs). The criteria shall describe the severity and extent of reliability impact that warrants establishment of an IROL, including:

6.1. Unacceptable quantity of load loss due to System instability, Cascading outages or uncontrolled separation;

6.2. Unacceptable quantity of supply loss due to System instability, Cascading outages or uncontrolled separation;

6.3. Unacceptable thresholds for inter-area oscillations (including acceptable damping criteria and criteria for inter-area oscillations versus intra-area oscillations); and,

6.4. Unacceptable impacts on neighboring Reliability Coordinator Areas within an Interconnection.

R7. Each Reliability Coordinator shall include in its SOL Methodology the criteria for developing the IROL T_V for any IROLs in its Reliability Coordinator Area. Each IROL T_V shall be less than or equal to 30 minutes.

R8. Each Reliability Coordinator shall include in its SOL Methodology the method to address a Real-time operating state, where the next Contingency has the potential to cause System instability, Cascading outages or uncontrolled separation, but was not identified one or more days prior to the current day. The method shall address:

8.1. Thresholds for initiating evaluation of potential impacts;

8.2. A description of when pre-Contingency Load shedding is warranted to mitigate the condition; and,

8.3. A review of the operating state experience for the purpose of determining whether an IROL should be established.

R9. Each Reliability Coordinator shall issue its SOL Methodology and any changes to the SOL Methodology, prior to the effective date, to:

9.1. Each adjacent Reliability Coordinator within an Interconnection, and each Reliability Coordinator that requested and indicated it has a reliability-related need for the SOL Methodology;

9.2. Each Planning Coordinator and Transmission Planner that models any portion of the Reliability Coordinator Area; and,

9.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

A. Introduction

1. **Title:** Establish and Communicate System Operating Limits
2. **Number:** FAC-014-3
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability:**

    4.1. Functional Entities:

    4.1.1. Reliability Coordinator

    4.1.2. Transmission Operator

    4.1.3. Planning Coordinator

    4.1.4. Transmission Planner

5. **Effective Date:** TBD

B. Requirements and Measures

R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area that are consistent with its System Operating Limit Methodology ("SOL Methodology") as established in FAC-011-4.

R2. Each Transmission Operator shall establish SOLs for its portion of the Reliability Coordinator Area consistent with its Reliability Coordinator's SOL Methodology.

R3. Each Reliability Coordinator shall determine stability limitations to be used in operations when the limitation impacts more than one Transmission Operator in its Reliability Coordinator Area consistent with its SOL Methodology.

R4. Each Reliability Coordinator shall provide the SOLs for its RC Area to adjacent Reliability Coordinators within an Interconnection and Reliability Coordinators who request and indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area.

4.1. The Reliability Coordinators shall provide any updates to the SOL values established as part of Requirement R1 or Requirement R3 to impacted TOPs in its Reliability Coordinators Area in a mutually agreeable periodicity and format.

R5. Each Reliability Coordinator with an established IROL shall provide the following IROL information to adjacent Reliability Coordinators within an Interconnection, to other Reliability Coordinators that indicate a reliability-related need for the information, and to the Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area:

5.1. Identification of the Facilities that are critical to the derivation of the IROL;

5.2. The value of the IROL and its associated IROL T_v;

5.3. The associated Contingency(ies); and,

5.4. The type of limitation represented by the IROL (*e.g.*, voltage collapse, angular stability).

R6. Each Reliability Coordinator with an established IROL shall provide the following IROL information to Transmission Owners and Generation Owners within its RC Area:

6.1. Identification of the Facilities that are owned by that entity, which are critical to the derivation of the IROL.

R7. The Transmission Operator shall provide any SOLs and updates to those limits to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.

R8. Each Planning Coordinator and Transmission Planner shall communicate the results of the stability analysis identified in its Planning Assessment and Transfer Capability assessment to each affected Reliability Coordinator and Transmission Operator. This shall include:

8.1. The type of the instability (*e.g.*, voltage collapse, angular instability, transient voltage dip criteria violation);

8.2. The Contingencies which result in the instability;

8.3. Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss that was employed (or invoked) to address the instability; and,

8.4. Any Corrective Action Plan associated with the instability.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Summary of Proposed Revisions

Project 2015-09 Establish and Communicate System Operating Limits

Do not use this form for submitting comments. Use the electronic form to submit comments on **Project 2015-09 Establish and Communicate System Operating Limits** (SOL). The electronic form must be submitted by **8 p.m. Eastern, Friday, August 12, 2016.**

Additional information is available on the project page. If you have questions, contact Lacey Ourso, Standards Developer by email or phone at 404.446.2581.

Background Information regarding Project 2015-09 Establish and Communicate System Operating Limits

The Facilities Design, Connections, and Maintenance (FAC) Reliability Standards fulfill an important reliability objective for determining and communicating System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) used in the reliable operation of the Bulk Electric System (BES). The purpose of Project 2015-09 – Establish and Communicate System Operating Limits is to revise these requirements. Revisions are necessary to eliminate overlap with approved Transmission Planning (TPL) requirements,[1] enhance consistency with Transmission Operations (TOP)[2] and Interconnection Reliability Operations (IRO)[3] standards, and address other concerns in the existing FAC standards regarding the determination and communication of SOLs and IROLs. As outlined in the Standards Authorization Request (SAR), the scope of the standards development project includes development of new or revised requirements and/or NERC Glossary definitions to provide clarity and consistency for establishing SOLs and IROLs, and to address potential reliability issues resulting from application of the current NERC Glossary definitions for SOL and IROL.[4]

High-level Overview of Proposed Revisions to FAC Reliability Standards

In developing revisions to the FAC Reliability Standards and definitions related to SOL and IROL, the standard drafting team (SDT) has focused on alignment with how SOLs and IROLs are treated in the approved TOP and IRO Reliability Standards (enforceable beginning April 1, 2017). The SDT believes this shift is critical to align the approach for how the System is actually operated as a result of the wholesale

[1] *See*, TPL-001-4
[2] *See*, TOP-001-3, TOP-002-4, TOP-003-3
[3] See, IRO-001-4, IRO-002-4, IRO-008-2, IRO-010-2, IRO-014-3, IRO-017-1
[4] The SAR was sponsored and submitted by the Project 2015-03 -Periodic Review of System Operating Limit Standards periodic review team (PRT).

revisions to the TOP and IRO Reliability Standards and reflects the manner in which operations are currently conducted. Below is a detailed explanation of how the proposed revisions complement the TOP/IRO revisions. The proposed changes to the FAC standards support a more reliable, dynamic approach to operating within actual limits that exist on the system, as opposed to reliance on "operating limits" that were set well in advance.

Overview of How Proposed Revisions Align with Revised TOP and IRO Reliability Standards

The revisions proposed to the FAC standards were designed to work together with the approved TOP and IRO Reliability Standards. The combination of the proposed revisions to the FAC standards and the TOP and IRO Reliability Standards, including the defined terms contained in those standards (Operational Planning Analysis (OPA)[5], Real-time Assessment (RTA)[6], and Operating Plans) when executed together will result in maintaining reliable BES performance. Thus, it is imperative that your review of the proposed revisions to the FAC standards is conducted with a full understanding of how these standards will work together with the approved TOP and IRO Reliability Standards. The proposed FAC revisions standing alone will not provide a complete picture of how different functional entities will work together to establish the appropriate operational limits, and then actually operate to them.

Under the approved TOP and IRO Reliability Standards:

- TOP-002-4 Requirement R1 requires the TOP to have an OPA that will allow it to assess whether its planned operations for the next day will exceed any of its SOLs.
- TOP-002-4 Requirement R2 requires that the TOP have an Operating Plan to address potential "SOL exceedances" identified as a result of its OPA.
- TOP-001-3 Requirement R13 requires that the TOP perform a RTA at least once every 30 minutes.

[5] NERC Glossary defines Operational Planning Analysis (OPA) as, "An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)" [NERC Glossary as of June 24, 2016]

[6] NERC Glossary defines Real-time Assessment (RTA) as, "An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) [NERC Glossary as of June 24, 2016]

- TOP-001-3 Requirement R14 requires that the TOP initiate its Operating Plan to mitigate an "SOL exceedance" identified as part of its Real-time monitoring or RTA.

For more information on the TOP/IRO revisions, please visit the Project 2014-03 Revisions to TOP/IRO Reliability Standards project page.

Overview of Proposed Revisions to FAC-011-3, FAC-014-2 and Defined Terms SOL and SOL Exceedance

As outlined in greater detail below, the SDT is proposing to revise the existing definition of SOL and create a new NERC Glossary definition for "SOL Exceedance." The new definitions support the conceptual distinction between operating practices and the SOL itself. The SOL is the actual set of Facility Ratings, System voltage limits, or stability limitations that are to be monitored for the pre- and post-Contingency state. How an entity operates to those SOLs can vary depending on the planning strategies, operating practices, and mechanisms employed by the entity. The revised definition of SOL and new definition of "SOL Exceedance" will work together with the future-enforceable TOP and IRO Reliability Standards, including the definitions of OPA, RTA and Operating Practices as follows:

- The TOP is required to have an OPA to assess whether its planned operations for the next day will exceed any of its SOLs (*see*, TOP-002-4, Requirement R1). If the OPA identifies potential SOL exceedances, the TOP is required to have an Operating Plan to address those potential SOL exceedances (*see*, TOP-002-4, Requirement R2).
- Additionally, the TOP is required to perform a RTA at least once every 30 minutes (*see*, TOP-001-3 Requirement R13). If the TOP identifies that an SOL is being exceeded in Real-time operations, the TOP will implement the mitigating strategies identified in its Operating Plan (*see*, TOP-001-3 Requirement R14).
- In other words, an "SOL Exceedance" is simply unacceptable system performance that must be mitigated in accordance with the action plan the TOP has laid out in its Operating Plan.
- A potential SOL Exceedance may be identified by an OPA, or an actual SOL Exceedance may be identified by an RTA.
- The Operating Plan can include specific Operating Procedures or more general Operating Processes. The TOP Operating Plans include both pre- and post- Contingency mitigation plans and strategies. The pre-Contingency strategies are implemented before the Contingency occurs to prevent the potential negative impacts on reliability of the Contingency. Post-Contingency mitigation plans and strategies are actions that the TOP will implement after the Contingency occurs to bring the system back within limits.
- The Operating Plans contain adequate details regarding the appropriate timelines to escalate the level of mitigation to ensure BES performance is maintained as required by the RC SOL Methodology.

The proposed definition of SOL Exceedance (described in further detail below) provides clarity regarding what is deemed to be "unacceptable system performance." When the conditions identified in the definition of SOL Exceedance occur, the TOP must be prepared to implement its action plan outlined in its Operating Plan to mitigate that particular condition and return the system back within acceptable limits.

The SDT believes that the proposed definitions and revisions to the FAC standards will eliminate confusion between the operating practices used by the TOP and the actual limits themselves. The revisions provide clarity regarding (1) what the limits are, (2) what it means to exceed them, and (3) how an "SOL Exceedance" should be addressed by the TOP in operations planning (TOP-002-4 Requirement R2) and Real-time operations (TOP-001-3 Requirement R14).

Purpose of 30-day Informal Comment Period

As outlined above, the scope of Project 2015-09 includes revision of the requirements for determining and communicating SOLs and IROLs used in the reliable planning and operation of the BES. This informal 30-day posting does not encompass the entire scope of work that the SDT will undertake for the project. Rather, this is only a piece of the complete work. However, the SDT believes it to be the most critical area. The direction taken with regard to these standards set the foundation for building a proper SOL methodology to ensure that SOLs are established and communicated in a manner that will later ensure reliable BES operation when carried out in operations.

Reliability Standards and definitions that **are included** (as part of this limited, informal posting):

- FAC-011-3 – System Operating Limits Methodology for the Operations Horizon
- FAC-014-2 – Establish and Communicate System Operating Limits
- Revisions to definition of System Operating Limit (SOL)
- New definition of SOL Exceedance

Reliability Standards and definitions that **are NOT included** (as part of this limited, informal posting):

- FAC-010-3 – System Operating Limits Methodology for the Planning Horizon
- Revisions to definition of Interconnection Reliability Operating Limit (IROL)
- Necessary revisions to existing Reliability Standards to incorporate concepts included in new defined term "SOL Exceedance" (*i.e.,* TOP-002-4 – capitalize SOL Exceedance to incorporate usage of defined term).

Although this is only an informal posting, the SDT underscores the importance of this posting. The SDT believes that the revisions proposed represent a significant improvement in how the industry works together to ensure reliability by establishing SOLs and operating to them in a manner that is reflective of the changing technology, and dynamic manner where entities have the ability to assess pre- and post-

Contingency performance in Real-time based on actual operating conditions. For these reasons, the SDT requests that commenters please take the time to review the background materials from the Project 2015-09 SOL Technical Conference which outline all of the various issues that were considered by the team, and discussed in an open forum with industry members. The SDT believes that we have captured the essence of the direction that the industry would like to take, but this is the opportunity for the team to continue to improve on proposed revisions by obtaining early feedback. The SDT looks forward to hearing and understanding your perspective for each of the very specific issues and associated questions raised below. In order for the SDT to thoroughly understand and incorporate your feedback into the future standard development, please do not simply provide yes or no responses. Please provide us with your perspective. Give us as much detail as you can. If you disagree with the SDT's direction, please provide an alternative approach that you believe will be superior to the one that the SDT proposed.

Proposed Revisions, Background Information and Questions

A. Definitions

Proposed Revisions to Definition of System Operating Limits (SOL)		
Proposed Revised Definition	**Explanation of Proposed Revision**	**Relevant Definition(s) or Standards Impacted By Proposed Revision**
System Operating Limits: Reliability limits used for operations, to include Facility Ratings, System voltage limits, and stability limitations.	The current definition of SOL (and the related FAC standards) presume an operating paradigm whereby a study or analysis is performed ahead of time to establish an SOL; the SOL is then communicated to operators; and the operators are given an operating plan to operate below the SOL with the presumption that doing so will result in acceptable pre- and post-Contingency system performance in Real-time operations. However, due to changes in the TOP and IRO Reliability Standards, along with advancements in technology from the time that the FAC standards were originally drafted, this is not reflective of how the system is actually operated. Today, entities continuously assess system performance and identify potential events in Real-time, based on *actual* operating conditions. The proposed revisions to the SOL definition, coupled with the proposed new definition of SOL Exceedance (see below) and the revisions to the FAC standards will support the concept that the SOL is the actual operating parameter; and eliminate confusion between "what the limits are" verses "how the system should be operated given the limits."	Existing definition of SOL: "The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings) • transient stability ratings (applicable pre- and post-Contingency stability limits) • voltage stability ratings (applicable pre- and post-Contingency voltage stability)

Proposed Revisions to Definition of System Operating Limits (SOL)		
Proposed Revised Definition	**Explanation of Proposed Revision**	**Relevant Definition(s) or Standards Impacted By Proposed Revision**
	Given this shift, there is no need for the existing SOL definition language that includes concepts of "the most limiting criteria," "specified system configuration," "operation within acceptable reliability criteria," and "pre- and post-Contingency." These concepts are covered in the future-enforceable TOP and IRO Reliability Standards (including the defined terms contained therein: OPA, RTA, and Operating Plans), along with the proposed revisions to the FAC standards. As a result of the proposed revisions, the Facility Ratings, System voltage limits, and stability limitations are SOLs, all of the time, regardless of which one is "the most limiting." Also, as detailed below, the definition of "SOL Exceedance" will complement the revised definition of SOL by specifically identifying operating conditions that are deemed unacceptable, and require action by the TOP to mitigate. The proposed revisions use the term "stability limitation" rather than "transient stability limit," "voltage stability limit" or the Glossary term "Stability Limit." The intent of the SDT is that "stability limitation" is intentionally broad and can be used to encompass a number of different types of stability-related limitations or phenomenon, including, but not limited to, weighted short-circuit ratio (WSCR), sub-synchronous resonance (SSR), phase angle limitations, fault-interrupting capability of breakers, transient voltage limitations on equipment, and geomagnetic-induced currents on equipment. The Glossary term "Stability Limits" is not appropriate because it is limited to the maximum power flow value; this is too restrictive and not technology-neutral, as tools allow entities	• system voltage limits (applicable pre- and post-Contingency voltage limits)"

Proposed Revisions to Definition of System Operating Limits (SOL)		
Proposed Revised Definition	**Explanation of Proposed Revision**	**Relevant Definition(s) or Standards Impacted By Proposed Revision**
	to monitor and control parameters other than maximum power flow values in order to demonstrate reliable stability performance. For more information regarding the proposed revisions to the SOL definition (and the definition of SOL Exceedance), please reference the Project 2014-03 – TOP and IRO Reliability Standards white paper entitled, "System Operating Limit Definition and Exceedance Clarification."	

Proposed New Definition of SOL Exceedance		
Proposed New Definition	**Explanation of Proposed New Definition**	**Relevant Definition(s) or Standards Impacted By Proposed New Definition**
SOL Exceedance: An operating condition characterized by any of the following: • Actual or pre-Contingency flow on a Facility is above the Normal Rating; • Calculated post-Contingency flow on a Facility is above the highest Emergency Rating;	As explained above, under the proposed revisions, the SOL is the actual set of Facility Ratings, System voltage limits, or stability limitations that are to be monitored for the pre- and post-Contingency state. How an entity remains within those SOLs will vary depending upon the particular Operating Plan of the entity. When the operating conditions listed in the definition of SOL Exceedance are identified – through an OPA or RTA – the TOP will take the actions outlined in its Operating Plan to mitigate the condition. The SDT did not include specific timing requirements for each condition listed in the definition, because the appropriate timing for operator response can vary depending upon the particular facts and	**Mapping to existing FAC standards or definitions under revision:** • FAC-011-3 Requirement R2 (Parts 2.1 and 2.2)- Identifies performance requirements that RC SOL Methodology shall include. If the definition of SOL Exceedance is pursued by the SDT, the definition would be incorporated into existing standards that currently rely on the concept of an

Proposed New Definition of SOL Exceedance		
Proposed New Definition	**Explanation of Proposed New Definition**	**Relevant Definition(s) or Standards Impacted By Proposed New Definition**
• Calculated post-Contingency flow on a Facility is above a Facility Rating for which there is not sufficient time to reduce the flow to acceptable levels should the Contingency occurs; • Actual or pre-Contingency bus voltage is outside normal System voltage limits; • Calculated post-Contingency bus voltage is outside the emergency system voltage limits; • Calculated post-Contingency bus voltage is outside emergency system voltage limits for which there is not sufficient time to relieve the condition should the Contingency occurs; or, • Operating parameters indicate the next Contingency could result in instability.	circumstances. However, it is expected (and required) that the TOP Operating Plan specifically identify the allowable response time, along with the specific actions to be taken by the operator, in mitigating the condition. The bulleted items carry forward the types of limitations that are identified in the current definition of SOL, and incorporate the concepts of acceptable/unacceptable system performance, as currently contained in FAC-011-3 Requirement R2. <u>For bullet item 3</u>: This operating condition exists when the calculated post-Contingency flow falls below the highest Emergency Rating; however, the flow remains at a level where there is not sufficient time to reduce the flow to an acceptable level after the Contingency occurs. In this operating condition, the operator would be required to take pre-Contingency action, and could not rely on a post-Contingency mitigation plan. Because pre-Contingency action is required, the condition is deemed to be an "SOL Exceedance." <u>For bullet items 4 and 5</u>: Normal and emergency System voltage limits must respect the voltage limitations specified in the TO or GO Facility Ratings methodology (pursuant to FAC-008-3). Normal voltage limits are typically applicable for the pre-Contingency state, while emergency voltage limits are applicable for the post-Contingency state. "SOL Exceedance" with respect to these voltage	"SOL exceedance." The intent is not to change the meaning of the existing standards, rather the SDT believes that the proposed definition captures the existing meaning, but simply provides greater clarity through listing the specific types of conditions in the "SOL Exceedance" definition. In concert with proposing the new "SOL Exceedance" definition, the SDT would propose revisions (only as necessary) to existing standards to incorporate the newly defined Glossary term. Below are a few examples, but are not intended to represent a comprehensive or complete listing: • <u>TOP-002-4 Requirement R1</u> - Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will result in an SOL Exceedance of its System Operating Limits (SOLs).

Proposed New Definition of SOL Exceedance		
Proposed New Definition	**Explanation of Proposed New Definition**	**Relevant Definition(s) or Standards Impacted By Proposed New Definition**
	limits occurs when either actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits, or when Real-time Assessments indicate that bus voltages are expected to fall outside acceptable emergency limits in response to a Contingency event. Real-time Assessments recognize whether auto-reactive devices are sufficient for maintaining voltage within acceptable limits pre- or post-Contingency.	• TOP-002-4 Requirement R2 - Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) Exceedance(s) identified as a result of its Operational Planning Analysis as required in Requirement R1. • TOP-001-3 Requirement R14 - Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL Exceedance identified as part of its Real-time monitoring or Real-time Assessment.

B. Proposed Revisions to FAC-011-3

Proposed Reliability Standard: FAC-011-4, Requirement R1		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R1. Each Reliability Coordinator shall have a methodology for establishing SOLs ("SOL Methodology") within its Reliability Coordinator Area.	As outlined above, the SDT has incorporated the concepts contained in the existing FAC-011-3 Requirement R1 into the proposed revisions to the definitions of SOL and SOL Exceedance, along with the proposed revisions to FAC-011 and FAC-14. The existing Parts 1.1 through 1.3 are incorporated into the proposed new requirements, as detailed below.	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R1 – Sentence 1.

Proposed Reliability Standard: FAC-011-4, Requirement R2		
Proposed New/Revised Requirement	**Explanation / Rationale for Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R2. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable Facility Ratings to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and	Under FAC-008-3, Facility Ratings are established by Facility owners (TOs and GOs) consistent with the owner's methodology. These Facility Ratings are communicated to the RCs and TOPs. RCs and TOPs incorporate these ratings into their tools and processes and use the ratings in establishing their SOLs. Because TOs and GOs are not required to use any sort of continent-wide methodology for establishing the Facility	**Background regarding existing standards *not* under revision by SDT:** • FAC-008-3 Requirements R1, R2 and R3– GOs and TOs are required to have a methodology for developing Facility Ratings. • FAC-008-3 Requirement R6– GOs and TOs shall establish Facility Ratings consistent with its methodology.

Proposed Reliability Standard: FAC-011-4, Requirement R2		
Proposed New/Revised Requirement	**Explanation / Rationale for Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
the Transmission Operators in its Reliability Coordinator Area.	Ratings, it is possible for owners to use varying/different methodologies. This can create problems in establishing the appropriate SOL because the variations in Facility Rating methodologies may result in different or inconsistent types of Facility Ratings used in operations. If the RCs and TOPs are using different sets of Facility Ratings in conducting their respective outage coordination studies, OPAs, and RTAs, this may create a potential risk to reliability. The intent of Requirement R2 is for the RC SOL Methodology to identify the method that its TOPs will use in determining which of the Facility Ratings provided by the owner (under FAC-008-3) are appropriate for use in establishing SOLs for use in operations. As outlined above, under the revised definition of SOL, the Facility Ratings will be the SOL. The second sentence of Requirement R2 is intended to ensure that the RC and the TOP are using the same Facility Ratings, which will eliminate the risk identified above.	• FAC-008-3 Requirements R7 and R8– must provide their Facility Ratings to the RC, TOP and other functional entities. **Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R1- RC SOL Methodology must state that SOLs shall not exceed associated Facility Ratings. • FAC-011-3 Requirement R2 (Parts 2.1 and 2.2)- RC SOL Methodology shall include requirement that SOLs provide BES performance, and following certain prescribed conditions/states, remain within their Facility Ratings.

Proposed Reliability Standard: FAC-011-4, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R3. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable steady-state System voltage limits to be used in operations. The method shall: **3.1.** Require that System voltage limits are not outside of the Facility voltage ratings; **3.2.** Require that System voltage limits are not outside of voltage limits identified in Nuclear Plant Interface Requirements; **3.3.** Require that System voltage limits are above UVLS relay settings; **3.4.** Identify the lowest allowable System voltage limit; **3.5.** Address the use of common System voltage limits between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area; and,	There is no Reliability Standard that specifically requires establishment and communication of System voltage limits; however, System voltage limits are used in the definition of SOL and are an important aspect of reliable operations. The SDT believes it is important for the Reliability Standards to assign responsibility for the establishment and communication of System voltage limits. Like Facility Ratings, System voltage limits should be consistent between TOPs and RCs throughout all operations processes. The proposed Requirement R3 will result in the RC SOL Methodology requiring the TOP to determine System voltage limits for use in operations, consistent with the RC methodology.	**Background regarding existing standards *not* under revision by SDT:** • FAC-008-3 – Requires Facility Owner to establish Facility Ratings, which includes voltage ratings.[7] • VAR-001-4 Requirement R1 – The TOP specifies the system voltage schedule (which is either a range or a target value associated with a tolerance band) as part of its plan to operate within SOLs (and IROLs). **Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R2 (Parts 2.1 and 2.2) - RC SOL Methodology shall include requirement that SOLs provide BES performance with regard to certain prescribed conditions (pre-Contingency state, following certain identified single-

[7] Definition of Facility Ratings: The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Proposed Reliability Standard: FAC-011-4, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
3.6. Address coordination of System voltage limits between adjacent Transmission Operators in its Reliability Coordinator Area.		Contingencies) and remain within their thermal and voltage limits. [Proposed definitions of SOL and SOL Exceedance and Requirement R3 carry this forward.] • FAC-011-3 Requirement R1- RC SOL Methodology must state that SOLs shall not exceed associated Facility Ratings. [Proposed Part 3.1 carries this forward.] • Parts 3.2-3.6 were not clearly identified in the previous FAC standards; these are "new" requirements added by the SDT to provide clarity regarding steady-state system voltage limits.

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R4. Each Reliability Coordinator shall include in its SOL Methodology the method for	As detailed above, the existing definition of SOL provides that the SOL is "based upon" certain criteria, including transient stability ratings. The proposed	**Background regarding existing standards *not* under revision by SDT:**

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
determining the stability limitations to be used in operations. The method shall: **4.1.** Specify stability performance criteria for single Contingencies and for multiple Contingencies (as identified in Requirement R5), including any margins applied. The criteria shall consider the following: **4.1.1.** steady-state voltage stability; **4.1.2.** transient voltage response; **4.1.3.** angular stability; and, **4.1.4.** System damping. **4.2.** Require that stability limitations are established to meet the BES performance criteria specified in Part 4.1 for the following Contingencies: **4.2.1.** Loss of one of the following either by single phase or three phase Fault to ground with normal clearing, or without a Fault: • generator;	revisions to the SOL definition make clear that the SOLs "are" the reliability limits, which include stability limitations. Additionally, under the current standards, there are no set continent-wide stability limitations criteria for use in determining SOLs. Under existing FAC-011-3 Requirement R2, the RC has flexibility with regard to establishing stability limitations; provided the system performance requirements in the standard are met. While the existing language in Requirement R2 (and portions of Requirement R3) do provide some "continent-wide" uniformity, the requirements do not provide sufficient clarity regarding the distinction between establishing stability limitations and acceptable system performance requirements/response. The proposed revisions continue to allow the RC to have flexibility in its SOL Methodology for developing stability limitations. This ensures the RC is able to appropriately tailor the methodology to meet the particular needs of its system, since a "one size fits all" approach is not appropriate for stability limitations. However, the proposed requirement does set a number of minimum	• <u>IRO-005-3.1a, Requirement R1 (Parts 1.2 and 1.3)</u> – Each RC should monitor its RC Area parameters, including pre and post contingent element stability conditions. • <u>IRO-008-2, Requirement R1</u> – Each RC shall perform an OPA that will assess whether next day planned operations will exceed SOLs or IROLs within its Wide-area. • <u>MOD-001-2, Requirement R1 (Part 1.1)</u> – Each TOP that calculates TFC or TTC shall have a written methodology that describes how those values are calculated, including the pre- and post-Contingency limitations for transient and voltage stability limits and other SOLs. **<u>Mapping to existing FAC standards under revision:</u>** • <u>FAC-014-2, Requirement R6 (Parts 6.1 and 6.2)</u> – Planning Authority shall provide multiple contingencies causing stability limits, and the limits, to the

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
• Transmission circuit; • transformer; • shunt device; • single pole of a direct current line. **4.2.2.** Loss of any multiple Contingencies identified in Requirement R5. **4.3.** Describe how instability risks are identified, considering realistic levels of transfers, Load and generation dispatch; **4.4.** Consider the stability limitations (and corresponding multiple Contingencies) provided by the Planning Coordinator in accordance with FAC-014-3 Requirement R8; **4.5.** Include a description of the study models, including the level of detail that is required and allowed uses of Remedial Action Schemes (RAS); and, **4.6.** Specify how stability limitations will be established when there is an impact to	required attributes (specific to stability limitations) that must be contained within the RC SOL Methodology. The proposed approach by the SDT is for the RC SOL Methodology to continue to set the method for how stability limitations for its RC Area must be established. Under proposed Requirement R4, the RC SOL Methodology must: Part 4.1 - Specify the stability performance criteria for single Contingencies and multiple Contingencies, including any margins applied. Part 4.2 - Meet the performance criteria for certain identified Contingencies (listed in the standard). Part 4.3 - Describe how instability risks are identified. The SDT changed the existing language of "anticipated" to "realistic." (See, FAC-011-3 Part 3.6) The SDT believes "anticipated" could be broadly interpreted to mean anticipated by the planners (in planning horizon), instead of what is realistically anticipated by the operators in the operations time horizon. Part 4.4 – Incorporates concepts from the existing FAC-011-3 Part 3.3, and requires the RC to consider the	Reliability Coordinator, or note to the RC if there are none. *[Maps to proposed Part 4.4]* • FAC-011-3 Requirement R2 (Part 2.1) - *[Maps to proposed Part 4.1, with new requirement providing specific types of criteria that must be considered.]* • FAC-011-3 Requirement R2 (Part 2.2) - *[Maps to proposed Part 4.2]* • FAC-011-3 Requirement R2 (Part 3.6) - *[Maps to proposed Part 4.3]* • FAC-011-3 Requirement R3 (Parts 3.1 and 3.5) – *[Maps to proposed Part 4.5]*

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
more than one TOP in its Reliability Coordinator Area.	stability limitations provided by the Planning Coordinator. Part 4.5 – This language combines some components of existing FAC-011-3 Parts 3.1, 4.3, and 3.5, but removes the blanket requirement for the study to include the entire RC Area. The revised language allows the RC to have flexibility to determine the appropriate study model, and required supporting details. Part 4.6 – The SDT believes that this Part will improve reliability by requiring the RC SOL Methodology to specify the appropriate manner to develop stability limitations, when those limitations impact more than one TOP in its RC Area. A companion requirement is FAC-014-3 Requirement R3, which requires the RC to determine the stability limitations when there is an impact to more than one TOP in its RC Area. (*See*, the proposed FAC-014-3 Requirement R3 for further explanation).	

Proposed Reliability Standard: FAC-011-4, Requirement R5		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R5. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the multiple Contingencies used in the evaluation for potential System instability, Cascading outages or uncontrolled separation.	Currently effective Reliability Standard TOP-004-2 Requirement R3 requires the TOP operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its RC. This requirement was retired by the TOP/IRO project because it was addressed by the new TOP-001-3 Requirements R12 and R14 (which are not limited by single or multiple contingencies) in combination with existing FAC-011-3 Part 3.3 and FAC-014-2 Requirement R6 (which work collectively to establish how multiple Contingencies are considered in IROLs and SOLs). The proposed Requirement R5 maintains the existing approach that the RC SOL Methodology shall specify the multiple Contingencies for use in establishing stability limitations and IROLs. Further, it improves upon the existing requirement by allowing the RC SOL Methodology to identify multiple Contingencies beyond those identified by the planners.	**Background regarding existing standards *not* under revision by SDT:** • TOP-001-3 Requirements R12 and R14 **Mapping to existing FAC standards under revision:** • FAC-011-3 Part 3.3 • FAC-014-2 Requirement R6

Proposed Reliability Standard: FAC-011-4, Requirement R6		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R6. Each Reliability Coordinator shall include in its SOL Methodology the method and criteria for establishing Interconnection Reliability Operating Limits (IROLs). The criteria shall describe the severity and extent of reliability impact that warrants establishment of an IROL, including: **6.1.** Unacceptable quantity of load loss due to System instability, Cascading outages or uncontrolled separation; **6.2.** Unacceptable quantity of supply loss due to System instability, Cascading outages or uncontrolled separation; **6.3.** Unacceptable thresholds for inter-area oscillations (including acceptable damping criteria and criteria for inter-area oscillations versus intra-area oscillations); and, **6.4.** Unacceptable impacts on neighboring Reliability	Regional differences exist in the criteria for determining which subset of SOLs are IROLs. The SDT discussed the regional differences among the various RC Areas, and several similarities emerged, including: (1) loss of load criteria, (2) loss of generation criteria, (3) non-localized or uncontained instability, and (4) impact on neighboring RC Area. The SDT evaluated the potential positive and negative impacts of creating continent-wide requirements, and determined that establishing minimum criteria that must be considered as part of the RC Methodology would benefit reliability; while continuing to allow necessary flexibility. The proposed language provides greater uniformity by identifying the criteria to be considered by the RC in establishing IROLs. The criteria must describe, at a minimum, the severity and extent of what is/not allowable with regarding to: (1) loss of load, (2) quality of supply loss, (3) thresholds for inter-area oscillations, and (4) impacts on neighboring RC Areas within its Interconnection. This minimum IROL criteria will provide for greater continent-wide consistency as it ensures all RCs consider and identify what is allowable for each criteria. The SDT believes while this does change the current state – where no mandatory minimum criteria exist- it still allows for the RC to have the necessary flexibility to design its IROL	**<u>Mapping to existing FAC standards under revision:</u>** • <u>FAC-011-3 Requirement R1</u> – RC SOL Methodology must include a description of how to identify the subset of SOLs that qualify as IROLs. • <u>FAC-011-3 Requirement R3.7</u>- RC SOL Methodology must include a description of the criteria for determining when violating an SOL qualifies as an IROL

Proposed Reliability Standard: FAC-011-4, Requirement R6		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
Coordinator Areas within an Interconnection.	methodology so that it can meet the reliability issues present in, and possibly unique to, its RC Area.	

Proposed Reliability Standard: FAC-011-4, Requirement R7		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R7. Each Reliability Coordinator shall include in its SOL Methodology the criteria for developing the IROL T_V for any IROLs in its Reliability Coordinator Area. Each IROL T_V shall be less than or equal to 30 minutes.	For the most part, the substance of this requirement is not changed from the existing standard; it was previously contained in a part (*i.e.,* FAC-011-3 Part 3.7) and is now a stand-alone requirement. The only change is that the 30 minute time-period is specifically identified, whereas in the previous requirement only stated T_v.	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R3.7- RC SOL Methodology must include a description of the criteria for determining when violating an SOL qualifies as an IROL and criteria for developing any associated IROL T_v.

Proposed Reliability Standard: FAC-011-4, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R8. Each Reliability Coordinator shall include in its SOL Methodology the method to address a Real-time operating state, where the next Contingency has the potential to cause System instability, Cascading outages or uncontrolled separation, but was not identified one or more days prior to the current day. The method shall address: **8.1.** Thresholds for initiating evaluation of potential impacts; **8.2.** A description of when pre-Contingency Load shedding is warranted to mitigate the condition; and, **8.3.** A review of the operating state experience for the purpose of determining whether an IROL should be established.	In Order No. 817, FERC noted that, "operators do not always foresee the consequences of exceeding such SOLs and thus cannot be sure of preventing harm to reliability." The SDT believes that in certain circumstances, such as in response to forced outages or similar unforeseen events, Real-time operating conditions can occur such that a RTA identifies an operating state where the next Contingency could result in instability, uncontrolled separation or Cascading outages. When this operating condition occurs in Real-time, it is clear that System Operator(s) are expected to take urgent action to mitigate the N-1 insecure operating state. What is unclear, however, is whether this operating condition constitutes some sort of an "IROL exceedance" or mandates that other IROL-related Reliability Standards should be applied. The proposed requirement requires the RC SOL Methodology to prescribe a method for how to address the above-described Real-time operating state. This will allow for consistency by System Operators within an RC Area in responding to the Real-time operating state when tools or analysis indicate abnormal post-Contingency conditions (*e.g.*, unsolved Contingencies, high post-Contingency overloads). While the requirement treats the operating state similar to, and equally important to, what prepared response must be	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R3.7- RC SOL Methodology must include a description of the criteria for determining when violating an SOL qualifies as an IROL and criteria for developing any associated IROL T_v.

Proposed Reliability Standard: FAC-011-4, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
	in place for resolving an IROL-type issue, the requirement does not focus on formally establishing the limit, but instead allowing the System Operator to act with urgency to address the temporary operating state at hand. Also Part 8.3 requires the RC Methodology prescribe an after-the-fact review of the operating state experience for the purpose of determining whether an IROL should be established in accordance with the RC SOL Methodology.	

Proposed Reliability Standard: FAC-011-4, Requirement R9		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R9. Each Reliability Coordinator shall issue its SOL Methodology and any changes to the SOL Methodology, prior to the effective date, to: **9.1.** Each adjacent Reliability Coordinator within an Interconnection, and each Reliability Coordinator that requested and indicated it has a reliability-related need for the SOL Methodology;	For the most part, the substance of this requirement is not changed from the existing standard. A clarification was added to Part 9.1 that RCs should issue its SOL Methodology, and any associated changes, to the other RCs *within* its Interconnection.	**<u>Mapping to existing FAC standards under revision:</u>** • <u>FAC-011-3 Requirement R4</u> – Requires the RC to issue its SOL Methodology, and any changes to the methodology, to its adjacent RCs and any RCs indicating a reliability-related need; to each PC and TP that models portions of its

Proposed Reliability Standard: FAC-011-4, Requirement R9		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
9.2. Each Planning Coordinator and Transmission Planner that models any portion of the Reliability Coordinator Area; and, **9.3.** Each Transmission Operator that operates in the Reliability Coordinator Area.		RC Area; and, each TOP that operates in its RC Area.

C. Proposed Revisions to FAC-014-3

Proposed Reliability Standard: FAC-014-3, Requirement R1		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area that are consistent with its System Operating Limit Methodology (“SOL Methodology”) as established in FAC-011-4.	The current FAC-014-2 Requirement R1 requires that the RC ensure SOLs and IROLs are established pursuant to its SOL Methodology. This creates a situation where the RC is responsible for “ensuring” actions out of its control. The proposed revisions do not change the intent of the standard –that the RC develop the SOL Methodology for establishing SOLs in its RC Area, and the TOP following the RC SOL Methodology in establishing those SOLs. Accordingly, the proposed Requirement R2 requires that the TOP establish SOLs as required by the RC SOL Methodology. The SDT believes this clarifies the appropriate responsibilities of the respective functional entities, while not creating ambiguity in the requirements in requiring the RC to do something that the TOP is, in all actuality, required to do. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R1 – Requires the RC to ensure SOLs and IROLs are establishing for its RC Area, consistent with its SOL Methodology. • FAC-014-2 Requirement R2 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Proposed Reliability Standard: FAC-014-3, Requirement R2		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R2. Each Transmission Operator shall establish SOLs for its portion of the Reliability Coordinator Area consistent with its Reliability Coordinator's SOL Methodology.	The SDT has removed language from the existing FAC-014-3 Requirement R2 that states the TOP, "shall establish SOLs (as directed by its Reliability Coordinator)" because it causes confusion and may be incorrectly understood to mean that the RC will issue a "Directive," or that TOPs are only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the drafting team has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs, and these SOLs must be established in accordance with (*i.e.*, pursuant to the "direction") identified in the RC's SOL Methodology.	**<u>Mapping to existing FAC standards under revision:</u>** • <u>FAC-014-2 Requirement R1</u> – Requires the RC to ensure SOLs and IROLs are establishing for its RC Area, consistent with its SOL Methodology. • <u>FAC-014-2 Requirement R2</u> – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Proposed Reliability Standard: FAC-014-3, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R3. Each Reliability Coordinator shall determine stability limitations to be used in operations when the limitation impacts	The proposed approach by the SDT is that the RC SOL Methodology will set the method for how all stability limitations for its RC Area must be established (see, proposed	**<u>Mapping to existing FAC standards under revision:</u>**

Proposed Reliability Standard: FAC-014-3, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
more than one Transmission Operator in its Reliability Coordinator Area consistent with its SOL Methodology.	FAC-011-4 Requirement R4). The RC SOL Methodology must, among other things, specify the stability performance criteria for single Contingencies and multiple Contingencies, including any margins applied (see, proposed FAC-011-4 Part 4.1); meet the performance criteria for certain identified Contingencies listed in the standard (see, proposed FAC-011-4 Part 4.2); and describe how instability risks are identified (see, proposed FAC-011-4 Part 4.3). The TOP is required to establish stability limitation SOLs in accordance with everything outlined in the RC SOL Methodology. However, in addition to what is outlined above, the SDT believes that to the extent there are stability limitations that may impact more than one TOP in its RC Area, the RC should be responsible for determining these stability limitations (in accordance with its RC SOL Methodology – see, proposed FAC-011-4 Part 4.6). The purpose of providing a separate requirement for the RC to address this specific type of stability limitation is to provide clarity that there may be a stability limitation that is not appropriately labeled an "IROL," and thus, would not be covered by proposed Requirement R1. It is the position of the SDT that not all stability limitations are automatically "IROLs." For example, there may be instances of local, contained instability that are not appropriately designated	• N/A: This proposed requirement addresses what the SDT believes to be a gap in the existing requirements.

Proposed Reliability Standard: FAC-014-3, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
	an "IROL," because labeling it as an IROL may require the TOP to take actions such as pre-Contingency load shedding, that is not warranted, and could actually cause a bigger reliability impact. However, when the stability limitation impacts more than one TOP, the SDT believes the RC should have primary responsibility for establishing that SOL.	

Proposed Reliability Standard: FAC-014-3, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R4. Each Reliability Coordinator shall provide the SOLs for its RC Area to adjacent Reliability Coordinators within an Interconnection and Reliability Coordinators who request and indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area. **4.1.** The Reliability Coordinators shall provide any updates to the SOL	The proposed Requirement R4 maintains the part of existing FAC-014-3 Requirement R5 which requires the TC to send the SOLs for its RC Area to adjacent RCs. The SDT has created a new/separate requirement related to communicating established IROLs (see proposed FAC-014-4 Requirement R5). The SDT added Part 4.1 to require the RC to provide updates to the SOLs to the impacted TOPs. It is expected that the RC and TOPs will establish a mutually agreeable means (pursuant to IRO-010-2 and TOP-003-3) for exchanging dynamically determined Facility Ratings or stability limitations.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R5 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Proposed Reliability Standard: FAC-014-3, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
values established as part of Requirement R1 or Requirement R3 to impacted TOPs in its Reliability Coordinators Area in a mutually agreeable periodicity and format.		

Proposed Reliability Standard: FAC-014-3, Requirement R5		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R5. Each Reliability Coordinator with an established IROL shall provide the following IROL information to adjacent Reliability Coordinators within an Interconnection, to other Reliability Coordinators that indicate a reliability-related need for the information, and to the Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area: **5.1.** Identification of the Facilities that are critical to the derivation of the IROL.	See above explanation. This requirement was previously combined with the requirement to provide updates to both SOLs and IROLs (existing FAC-014-3 Requirement R5). The SDT separated these into two requirements – one for SOL and one for IROL – so that greater detail could be provided regarding the type of IROL-information that must be communicated by the RC.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R5 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Proposed Reliability Standard: FAC-014-3, Requirement R5		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
5.2. The value of the IROL and its associated IROL T_v. **5.3.** The associated Contingency(ies). **5.4.** The type of limitation represented by the IROL (*e.g.*, voltage collapse, angular stability).		

Proposed New/Revised Requirement	Explanation of Proposed Revision	Relevant Requirements in Existing Reliability Standard(s)
R6. Each Reliability Coordinator with an established IROL shall provide the following IROL information to Transmission Owners and Generation Owners within its RC Area: **6.1.** Identification of the Facilities that are owned by that entity, which are critical to the derivation of the IROL.	In FERC Order No. 777, FERC directed NERC to develop a means to assure that IROLs are communicated to transmission owners (*see*, P6 and P41). The purpose of this proposed requirement is to address the concerns raised by FERC in Order No. 777. The RC is required to provide the IROL information identified in Part 6.1 to Transmission Owners and Generator Owners in its RC Area. The SDT included Generator Owners because it believes that GOs, in addition to TOs, need to receive information relating to facilities that are critical to the derivation of the IROL. The SDT did not combine this with proposed Requirement R5 because the team believes that the owners only need IROL information related to their facilities that are critical to the	**<u>Mapping to existing FAC standards under revision:</u>** • <u>N/A</u>: This proposed requirement is intended to address the issues raised in FERC Order No. 777.

Proposed New/Revised Requirement	Explanation of Proposed Revision	Relevant Requirements in Existing Reliability Standard(s)
	derivation of the IROL. However, the owners do not need the information identified in proposed Parts 5.2 through Part 5.4, and further, this information may contain sensitive operator information not appropriate for open-ended sharing.	

Proposed Reliability Standard: FAC-014-3, Requirement R7		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R7. The Transmission Operator shall provide any SOLs and updates to those limits to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.	The SDT did not make substantive changes to this requirement; however, the requirement previously existed as a "part" of a requirement and it is now a stand-alone requirement.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Part 5.2 – Requires the TOP to provide its SOLs to the RC and Transmission Service Providers in its portion of the RC Area.

Proposed Reliability Standard: FAC-014-3, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**

Proposed Reliability Standard: FAC-014-3, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R8. Each Planning Coordinator and Transmission Planner shall communicate the results of the stability analysis identified in its Planning Assessment and Transfer Capability assessment to each affected Reliability Coordinator and Transmission Operator. This shall include: **8.1.** The type of the instability (*e.g.*, voltage collapse, angular instability, transient voltage dip criteria violation); **8.2.** The Contingencies which result in the instability; **8.3.** Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss that was employed (or invoked) to address the instability; and, **8.4.** Any Corrective Action Plan associated with the instability.	Under proposed FAC-011-4 Part 4.4, the RC SOL Methodology must consider the stability limitations provided by the Planning Coordinator. Also, proposed FAC-014-3 Requirements R2 and R3, the applicable entities are required to establish stability limitations (if any) in accordance with the RC SOL Methodology. This requirement is intended to complement proposed FAC-011-4 Part 4.4 by ensuring that the planning entities provide the results of their stability analysis, including a list of those contingencies that are expected to produce the more severe System impacts, to the affected RC and TOP. This information may be relevant to the operating conditions for which the RC and TOP are determining SOLs. Further, FAC-013-2 requires that the PC have a methodology and annual assessment that identifies the weaknesses and limiting Facilities that could limit the ability of the Transmission System to reliably transfer energy. The results of the assessment, including the methodology used in the analysis, may contain information that may be relevant to the RC and TOP analysis for determining SOLs (and IROLs).	<u>**Background regarding existing standards *not* under revision by SDT:**</u> • <u>TPL-001-4</u> • <u>FAC-013-2</u> <u>**Mapping to existing FAC standards under revision:**</u> • <u>FAC -011-3 Part 3.3</u> • <u>FAC -014-2 Requirement R6</u>

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Functional Model

~~Function Definitions and Functional Entities~~

Version 6~~5~~

Prepared by the Functional Model Advisory Group
Approved by the Standards Committee: [Month, Year]

RELIABILITY | ACCOUNTABILITY




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Table of Contents

~~Section I: Purpose of the Functional Model~~~~Part 1: Foreword~~

The functional model (FM) is a guideline that identifies the functions that must be performed to ensure that the Bulk Power System is planned and operated in a reliable manner. The FM describes, in general terms, the functions that must be performed to ensure reliability, the specific tasks that are necessary to perform each function, and the relationships between functional entities that perform the various tasks. In its capacity of a guideline, the FM serves to provide a framework for NERC Reliability Standards as they are developed through the standard development process. The FM is independent of any particular organizational or market structure. The focus of the FM is solely on identification of reliability-related functions and the associated tasks and relationships.

Equally important to explaining what the FM does do, is a clear explanation of what the FM does **not** do. The FM is **not** a mandatory and enforceable document. The FM is **not** a “standard” and does not have compliance effects. If there is a conflict between the FM and Reliability Standards, the Reliability Standards always take precedence. The FM is only a guideline serving to provide details on how the different functions work together to ensure the reliability of our BPS. Also, the FM is **not** intended to identify the entities responsible for NERC registration. The NERC registration process is undertaken by NERC (and the Regional Entities) pursuant to authority from FERC, ultimately derived from the Federal Power Act. The FM has no authority, ability, or intent to impact or influence the NERC Registration process. Below is an overview of the NERC Registration process, which is completely separate from, and should not be confused with, the FM guideline. Similar to conflicts with Reliability Standards, if the FM and NERC Registration do not align, NERC Registration takes precedence.

~~This document replaces version 4 of the NERC Reliability Functional Model that the NERC Standing Committees approved in September 2008.~~

~~Historically, Control Areas were established by vertically integrated utilities to operate their individual power systems in a secure and reliable manner and provide for their customers’ electricity needs. The traditional Control Area operator balanced its load with its generation, implemented Interchange Schedules with other Control Areas, and ensured transmission reliability.~~

~~As utilities began to provide transmission service to other entities, the Control Area also began to perform the function of Transmission Service Provider through tariffs or other arrangements. NERC’s Operating Policies reflected this traditional electric utility industry structure, and ascribed virtually every reliability function to the Control Area.~~

~~Beginning in the early 1990s with the advent of open transmission access and restructuring of the electric utility industry to facilitate the operation of wholesale power markets, the functions performed by Control Areas began to change to reflect the newly emerging industry structure. These changes occurred because:~~

1. ~~Some utilities were separating their transmission from their merchant functions (functional unbundling), and even selling off their generation;~~
2. ~~Some states and provinces were instituting “customer choice” options for selecting energy providers; and,~~
3. ~~The developing power markets were requiring wide-area transmission reliability assessment and dispatch solutions, which were beyond the capability of many Control Areas to perform.~~

~~As a result, the NERC Operating Policies in place at that time, which centered on Control Area operations, were beginning to lose their focus, and become more difficult to apply and enforce.~~

~~The NERC Operating Committee formed the Control Area Criteria Task Force (CACTF) in 1999 to address this problem. The task force began by listing all the tasks required for maintaining electric system reliability and then~~

~~organizing these tasks into basic groups that it called "functions." Ultimately, the Task Force decided to build a "Functional Model." This involved breaking down the previous reliability functions more finely, such that all organizations involved in ensuring reliability —whether they are traditional, vertically integrated control areas, regional transmission organizations, independent system operators, independent transmission companies or so on— can identify those functions they perform, and register with NERC as one or more of the functional entities. Initially the Model dealt with operating functions, but it was subsequently expanded in Version 2 to incorporate planning-related functions. This Functional Model framework provides guidance to NERC standards drafting teams to write reliability standards in terms of the functional entities who perform the reliability functions.~~

~~Adapted from Version 2 of the NERC Functional Model, February 10, 2004.~~

Section II: Overview of the NERC Registration Process~~Part 2: Introduction~~

The NERC Registration process consists of several elements, including the NERC Registry Criteria and the NERC Compliance Registry, and involves both the Regional Entities and NERC. The process for registration is described in the NERC Rules of Procedure, Section 500 (Appendix 5A: Organization Registration and Certification Manual and Appendix 5B: Statement of Compliance Registry Criteria).

The starting point for the NERC program for monitoring and enforcing compliance with FERC-approved Reliability Standards is the process for comprehensively 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.[1] The NERC Registry Criteria provides for Bulk Power System users, owners and operators that perform a function identified in Section II of the Registry Criteria, and have a material impact on Bulk Power System reliability (which is generally determined by whether they meet the threshold criteria in Section III of the Registry Criteria) to register as one or more of fifteen functions. NERC and the Regional Entities identify such entities, which are then obligated to comply with Commission-approved Reliability Standards.[2] Identified entities are registered and included on the NERC Compliance Registry.[3] The NERC Compliance Registry identifies the reliability functions that each registered entity is responsible for meeting pursuant to 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).[4] The registration criteria for the reliability functions are specified in the NERC Statement of Compliance Registry Criteria.[5]

The potential costs and effort of registering every organization potentially within the scope of "owner, operator, and user of the BPS," while ignoring their impact upon reliability, would be disproportionate to the improvement in reliability that would reasonably be anticipated from doing so. Therefore, the two stated goals for registration are: (1) consistency between and among Regional Entities and across the continent in the application of the criteria for registering entities; and (2) registration of any entity whose facilities or operations are deemed material to the reliability of the Bulk Power System, irrespective of other considerations.[6]

~~The NERC Reliability Functional Model provides the framework for the development and applicability of NERC's Reliability Standards as follows:~~

- ~~The Model describes a set of Functions that are performed to ensure the reliability of the Bulk Electric System. Each Function consists of a set of related reliability Tasks. The Model assigns each Function to~~

[1] *See*, Order on Electric Reliability Organization Risk Based Registration Initiative and Requiring Compliance Filing, Docket No. RR15-4-000, 150 ¶ 61,213 (March 15, 2015).

[2] Section 215(b)(2) of the Federal Power Act (FPA) requires all users, owners and operators of the Bulk Power System 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 Bulk-Power System to comply with applicable Reliability Standards and applicable rules of the ERO and Regional Entities approved by the Commission.

[3] NERC Statement of Compliance Registry Criteria (Registry Criteria) at 2 (*"Organizations will be responsible to register and to comply with approved Reliability Standards to the extent that they are owners, operators, and users of the Bulk Power System, perform a function listed in the functional types identified in Section II of this document, and are material to the Reliable Operation of the interconnected Bulk Power System as defined by the criteria and notes set forth in this document."*).

[4] *See*, NERC Rules of Procedure §501. The current categories of reliability functional entities are listed in Rules of Procedure Appendix 5B, Statement of Compliance Registry Criteria.

[5] *See*, NERC Rules of Procedure, Appendix 5B.

[6] *See*, NERC Rules of Procedure, Appendix 5B at 4.

~~a functional entity, that is, the entity that performs the function. The Model also describes the interrelationships between that functional entity and other functional entities (that perform other Functions).~~

- ~~NERC's Standards Development Teams develop Reliability Standards that assign each reliability requirement within a standard to a functional entity (that is defined in the Model and NERC's Glossary). This is possible because a given standard requirement will typically be related to a Task within a Function. A standard requirement will be very specific, whereas a Task in the Model will be more general in nature.~~
- ~~NERC's compliance processes require specific organizations to register as the entities responsible for complying with standards requirements assigned to the applicable entities.~~
- ~~The Model's Functions and functional entities also provide for consistency and compatibility among different Reliability Standards.~~

~~The Model is a guideline for the development of standards and their applicability. The Model it is not a Standard and does not have compliance requirements. Standards developers are not required to include all tasks envisioned in the model, nor are the developers precluded from developing Reliability Standards that address functions not described in the model. Where conflicts or inconsistency exist, the Reliability Standards requirements take precedence over the Model.~~

~~The Model is independent of any particular organization or market structure. An organization may perform more than one Function.~~

~~The Functional Model describes a functional entity envisioned to ensure that all of the Tasks related to its Function are performed. The Model, while using the term "functional entity", is a guideline and cannot prescribe responsibility. It is NERC's compliance processes, backed by regulatory authority, that specify the manner in which, a functional entity is "legally responsible" for meeting the standards requirements assigned to that functional entity.~~

~~The work performed to meet the requirements may be self-performed or performed by others.~~

~~**Functional Model maintenance.** The Functional Model is maintained by the Functional Model Working Group (FMWG) under the direction of the NERC Standards Committee, with technical content in the Model and accompanying technical document approved by the Standing Committees (OC, PC and CIPC).~~

~~**Technical discussions**. The companion document, "Functional Model – Technical Discussions," provides additional details on the Functions themselves, how organizations can "roll up" those Functions they wish to perform, and how organizations as "functional entities" interrelate.~~

~~**The following terms are used in the Functional Model and do not appear in the NERC Glossary.**~~

~~**Functional Entity.** The term used in the Functional Model which applies to a class of entity that carries out the Tasks within a Function.~~

~~**Function**. A set of related reliability Tasks.~~

~~**Task**. One of the elements that make up a Function in the Functional Model.~~

~~**Customer**. The term applies to a customer for transmission, capacity or energy services (a Purchasing-~~

~~Selling Entity, Generator Owner, Load-Serving Entity, or End-use Customer).~~

~~**End-use Customer.** The party served by a Load-Serving Entity (energy) and Distribution Provider (wire service).~~

~~Purpose of the Functional Model~~

~~The purpose of the NERC Reliability Functional Model is to:~~

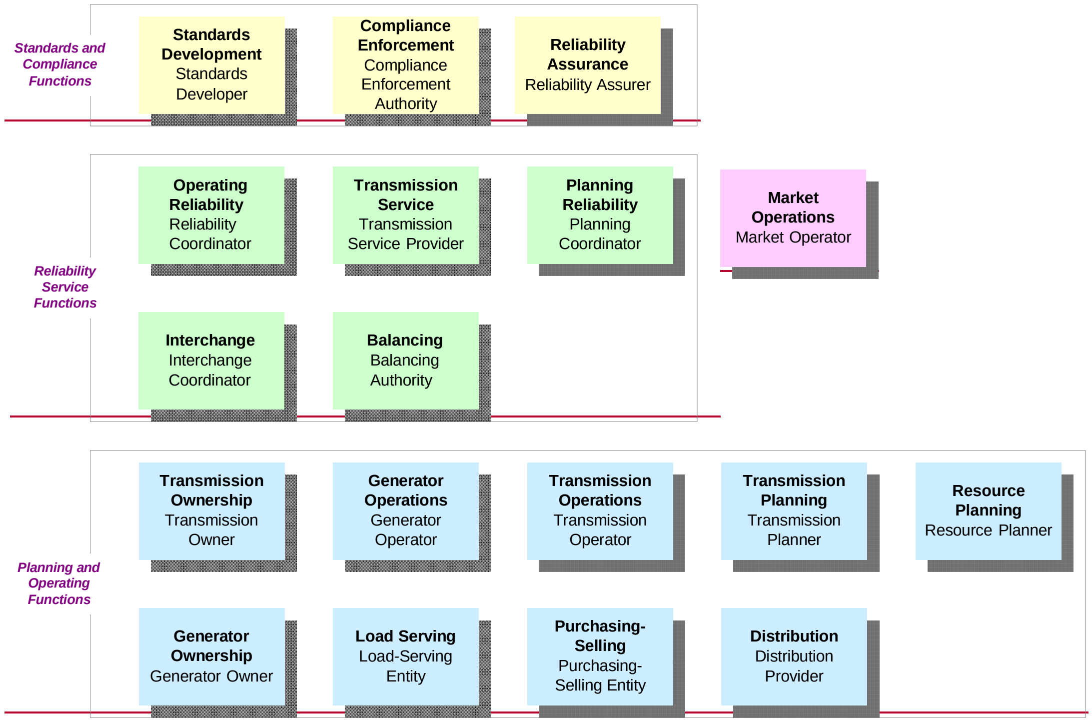
1. ~~Provide a framework for Reliability Standards developed through the NERC standards development process that will apply to certain Tasks defined in the Functional Model.~~

- ~~Describe in general terms each Function and the relationships between the entities that are responsible for performing the Tasks within the Functions. The framework for developing the Function definitions is:~~

    - ~~The Functions are independent of the organization structure performing the functions, and~~

    - ~~The Functions provide flexibility to accommodate the range of presently conceivable organization structures, as well as accommodate alternative tools, procedures and processes.~~

~~Functional Model Diagram~~



~~*Function Name*~~	~~*Functional Entity*~~
~~Balancing~~	~~Balancing Authority~~
~~Compliance Enforcement~~	~~Compliance Enforcement Authority~~
~~Distribution~~	~~Distribution Provider~~
~~Generator Operations~~	~~Generator Operator~~
~~Generator Ownership~~	~~Generator Owner~~
~~Interchange~~	~~Interchange Coordinator~~
~~Load-Serving~~	~~Load-Serving Entity~~
~~Market Operations~~	~~Market Operator (Resource Integrator)~~
~~Operating Reliability~~	~~Reliability Coordinator~~
~~Planning Reliability~~	~~Planning Coordinator~~
~~Purchasing-Selling~~	~~Purchasing-Selling Entity~~
~~Reliability Assurance~~	~~Reliability Assurer~~
~~Resource Planning~~	~~Resource Planner~~
~~Standards Development~~	~~Standards Developer~~
~~Transmission Operations~~	~~Transmission Operator~~
~~Transmission Ownership~~	~~Transmission Owner~~
~~Transmission Planning~~	~~Transmission Planner~~
~~Transmission Service~~	~~Transmission Service Provider~~

~~Guiding Principles of the Functional Model~~

~~As explained in the Introduction, the Model provides the framework on which the NERC Reliability Standards are developed and applied. To ensure that this framework remains viable, the Model itself is governed by a set of "guiding principles" that define a Function's Tasks and establish the relationships between the functional entities which are responsible for meeting the requirements in the NERC Reliability Standards that correspond to these Tasks. These principles serve as a guideline to those revising or interpreting the Model.~~

~~For further details, refer to the Technical Discussions section in the Functional Model Technical Document.~~

~~0. The Model must be *complete*, that is, it must include all reliability Tasks and interrelationships between entities performing them. This helps ensure that any reliability requirement arising in a Reliability Standard will generally be related to a Task in the Model and therefore be assignable to a particular functional entity.~~

~~0. The Model must group these Tasks into a set of Functions, such that:~~

- ~~There are enough Functions (and corresponding functional entities) to accommodate the full range of organization structures and responsibilities within the industry, and~~
- ~~The number of Functions is developed based on logical grouping of the Tasks and kept low as reasonably possible.~~
    - ~~In particular, where a number of organizations that perform a given Function form a single group, the Model recognizes this as a business arrangement among organizations, not a new Function and corresponding new functional entity. That is, the fundamental reliability Tasks, and hence the Function, remain the same – all that has changed is *how* the Function is performed. Examples of such groups are a reserve sharing group (a collection of entities that are Balancing Authorities), or a planned resource sharing group.~~

~~0. The Model is structured to ensure there are no gaps or overlaps in the performance of operation Tasks in the operating timeframe anywhere in the Bulk Electric System. This is achieved in part by associating an "area" of purview for each functional entity. Areas are defined in term of the individual transmission, generator and customer equipment assets that collectively constitute the Bulk Electric System. For example, each Bulk Electric System asset has one Reliability Coordinator, one Balancing Authority, and one Transmission Operator. Regarding overlaps for planning, as described in the Technical Document, it is not always possible to achieve this in the case of planning Functions, where there may be overlapping levels of responsibility for given assets. Questions regarding relationships between the areas of different functional entities, such as whether one type of area must be totally within another type of area, will be defined in Reliability Standards or the Rules of Procedure, not the Model.~~

~~0. Tasks describe *what* is to be done, not *how* it is to be done.~~

~~0. The Model is a guideline that describes reliability Tasks and interrelationships between the entities that perform them – it is not prescriptive. In particular, the Model does not address requirements for registering or becoming certified as a functional entity, or the delegation or splitting of responsibility for meeting standards requirements.~~

~~Clarification Service~~

~~The Functional Model is a reference tool that links functional entities with associated reliability- related functions and respective Tasks. Drafting teams use the Functional Model to help them determine which functional entity should be required to comply with each requirement in a reliability standard.~~

~~From time to time questions of clarification and interpretation arise. The FMWG is following the process described below for handling requests for clarification of the Functional Model. This process, which has been approved by the Standards Committee, is accessible to all drafting teams as well as any other interested stakeholders. If a drafting team needs help in understanding Tasks that make up a Function and/or in determining which functional entities should be responsible for particular standards requirements, the drafting team's coordinator will send an e-mail to the NERC Staff assigned as the FMWG facilitator with a request for clarification.~~

0. ~~The NERC Staff assigned as the FMWG facilitator will convene a conference call/meeting of available members of the FMWG to review the question(s) and provide a clarification.~~
   - ~~If the question(s) need more detailed discussion with the drafting team, the two coordinators will organize a conference call/meeting with available members of the FMWG and available members of the drafting team to discuss the issues in more detail.~~
0. ~~Each FMWG request for clarification and the associated response will be posted on the NERC Functional Model Web Page under a Frequently Asked Questions section.~~
   - ~~If the questions result in changes to the model, the changes will be added to a change summary table used to develop the next updated version of the Functional Model document.~~

Section III: ~~Part 3:~~ Functions and Functional Entities

This section defines the reliability-related functions and functional entities that perform the associated ~~T~~tasks that are necessary to plan and operate the Bulk Electric System in a reliable manner. This section also identifies the relationships between various functional entities that are formed in order to perform the reliability-related tasks. ~~characterizes the functional entities that perform these Tasks, and provides examples of the inter-relationships that take place between entities to ensure reliability. As standards are developed, the Model may be revised to add and remove Tasks under specific Functions to aid in the development of standards. Relationships between functional entities in the Model are reciprocal. Where~~ In some instances, a one-to-one relationship may exist~~s~~ between two functional entities; in other instances, there may be ~~, the Model will include the reciprocal relationship specifically; and where~~ a one-to-many relationship. ~~exists, the reciprocal relationships are implied.~~

~~Functional Model Diagram~~

~~Standards Development and Standards Developer~~

~~Standards Development~~

~~Tasks~~

0. ~~Develop and maintain a standards development process.~~
0. ~~Develop Reliability Standards for the planning and operation of the Bulk Electric System.~~

~~Standards Developer~~

~~Definition~~

~~The functional entity that develops and maintains Reliability Standards to ensure the reliability of the Bulk Electric System.~~

~~Introduction to the Standards Developer~~

~~The Model addresses Reliability Standards created at NERC using the NERC Reliability Standards Development Procedure and Regional Standards that are created through an open Regional process and approved by NERC for enforcement. The Functional Model is intended to serve as the framework for the development and application of these Reliability Standards.~~[7]

~~Relationships with Other Functional Entities~~

~~0. Receives request for Reliability Standards through the public process.~~

~~0. Sends Reliability Standards to the Compliance Enforcement Authority.~~

[7] ~~There are also Regional Criteria that are requirements that Regions create and enforce, that are not included in the Model.~~

~~Compliance Enforcement and Compliance Enforcement Authority~~

~~Compliance Enforcement~~

~~Tasks~~

~~0. Develop, maintain and implement a compliance enforcement process.~~

~~0. Evaluate and document compliance.~~

~~Compliance Enforcement Authority~~

~~Definition~~
~~The functional entity that monitors, reviews, and ensures compliance with Reliability Standards and administers sanctions or penalties for non-compliance to the standards.~~

~~Relationships with Other Functional Entities~~

~~2. Receives Reliability Standards from the Standards Developer.~~

~~3.~~1. ~~Administers the compliance enforcement process for all functional entities as required by Reliability Standards.~~

Reliability Assurance and Reliability Assurer

Reliability Assurance

Tasks

1. Develop and maintain Reliability Standards that apply to Bulk Power System owners, operators, and users and that enable the Reliability Assurer to measure the reliability performance of Bulk Power System owners, operators, and users; and to hold them accountable for Reliable Operation of the Bulk Power Systems.
2. Develop and implement a compliance and enforcement program to promote the reliability of the Bulk Power System by enforcing compliance with approved Reliability Standards in those regions of North American in which the Reliability Assurer has been given enforcement authority.
3. Develop and maintain a program for identifying and registering those entities that are responsible for compliance with the governmental-approved Reliability Standards.
4. Provide for certification of all entities with primary reliability responsibilities requiring certification.
5. Provide a mechanism to ensure system operators are provided the education and training necessary to obtain the essential knowledge and skills and are therefore qualified to operate the BES.
6. Provide reliability readiness evaluation and improvement, and formation of sector forums if necessary for reliability.
7. Develop a reliability assessment and performance analysis program that conducts reviews and assessments of the overall reliability of the interconnected BPS, including:
    - Review, assess, and report on the overall electric generation and transmission reliability (adequacy and operating reliability) of the interconnected Bulk Power Systems, both existing and as planned.
    - Assess and report on the key issues, risks, and uncertainties that affect or have the potential to affect the reliability of existing and future electric supply and transmission.
    - Review, analyze, and report on Regional Entity self-assessments of electric supply and bulk power transmission reliability, including reliability issues of specific regional concern.
    - Identify, analyze, and project trends in electric customer demand, supply, and transmission and their impacts on Bulk Power System reliability.
    - Investigate, assess, and report on the potential impacts of new and evolving electricity market practices, new or proposed regulatory procedures, and new or proposed legislation (e.g. environmental requirements) on the adequacy and operating reliability of the Bulk Power Systems.
8. Provide leadership, coordination, technical expertise, and assistance to the industry in responding to a major event.
9. Provide the education and training necessary for Bulk Power System personnel and regulators to obtain the essential knowledge necessary to understand and operate the BES.
10. Through the use of appropriate functional entities and available tools, monitor present conditions on the Bulk Power System and provide leadership coordination, technical expertise, and assistance to the industry in responding to events as necessary.

11. Coordinate electric industry activities to promote Critical Infrastructure protection of the Bulk Power System in North America by taking a leadership role in Critical Infrastructure protection of the electricity sector so as to reduce vulnerability and improve mitigation and protection of the electricity sector's Critical Infrastructure.

~~1. Coordinate reliability assurance among adjacent Reliability Assurers through the development of necessary protocols and processes.~~

~~1. Coordinate the activities related to maintaining critical infrastructure protection.~~

~~1. Establish reliability assurance processes and documentation related to planning and operations within the Reliability Assurer's area including such things as a regional reliability plan or a Reliability Coordinator plan.~~

~~1. Identify and address gaps in reliability processes and responsibilities.~~

Reliability Assurer

Definition

Subject to oversight by the Federal Energy Regulatory Commission and governmental authorities in Canada, assure the reliability of the Bulk Power System in North America by developing and enforcing Reliability Standards; annually assessing seasonal and long-term reliability; monitoring the Bulk Power System through system awareness; and, educating, training, and certifying industry personnel. ~~The functional entity that monitors and evaluates the activities related to planning and operations, and coordinates activities of functional entities to secure the reliability of the Bulk Electric System within a Reliability Assurer area and adjacent areas.~~

Relationships with Other Functional Entities

1. Develop Reliability Standards that identify the functional entities responsible for complying with the Reliability Standard, including: Reliability Coordinators, Balancing Authorities, Transmission Operators, Transmission Owners, Generator Operators, Generator Owners, Transmission Service Providers, Planning Coordinators, Transmission Planners, Resource Planners, and Distribution Providers.

2. Obtain the information necessary to monitor compliance with Reliability Standards from functional entities, including: Reliability Coordinators, Balancing Authorities, Transmission Operators, Transmission Owners, Generator Operators, Generator Owners, Transmission Service Providers, Planning Coordinators, Transmission Planners, Resource Planners, and Distribution Providers.

3. Obtain the information necessary to complete registration from the appropriate functional entities, including: Reliability Coordinators, Balancing Authorities, Transmission Operators, Transmission Owners, Generator Operators, Generator Owners, Transmission Service Providers, Planning Coordinators, Transmission Planners, Resource Planners, and Distribution Providers.

~~0. Coordinates reliability assurance activities of the functional entities within the Reliability Assurer area.~~

~~0. Coordinates reliability assurance activities with adjacent Reliability Assurers.~~

~~0. Coordinates critical infrastructure protection programs with functional entities.~~

~~0. Collects information from functional entities related to Reliability Assurance processes.~~

Planning Reliability and Planning Coordinator

Planning Reliability

Tasks

1. Establish data requirements necessary to develop power system models for analysis within the Planning Coordinator area. ~~Develop and maintain methodologies for the analysis and simulation of the transmission systems in the evaluation and development of transmission expansion plans and the analysis and development of resource adequacy plans.~~

2. Collect and validate information from Transmission Planners, such as modeling data, to perform a Transmission assessment of the Planning Coordinator area. ~~Define information required for planning purposes, and facilitate the process for consolidating and collecting or developing such information, including:~~

   - ~~Transmission facility characteristics and ratings.~~
   - ~~Demand and energy forecasts, capacity resources, and demand response programs.~~
   - ~~Generator unit performance characteristics and capabilities.~~
   - ~~Long-term capacity purchases and sales.~~

~~7.~~3. Assess the performance of the Transmission system, with the loads, resources, and proposed projects included in the Transmission Planner's Planning Assessment (including any Corrective Action Plan(s)). ~~Evaluate, develop, document, and report on resource and transmission expansion plans for the Planning Coordinator area. Integrate the respective plans, evaluate the impact of those plans on and by adjoining Planning Coordinator's integrated plans and assess whether the integrated plan meets reliability needs, and, if not, then to report on potential transmission system and resource adequacy deficiencies and suggest or facilitate the process for developing alternative plans to mitigate identified deficiencies.~~

   - ~~Evaluate the plans that are in response to long-term (generally one year and beyond) customer requests for transmission service.~~
   - ~~Review transmission facility plans required to integrate new (End-use Customer, generation, and transmission) facilities into the Bulk Electric System.~~
   - ~~Review and determine transfer capability (generally one year and beyond) as appropriate.~~
   - ~~Monitor and evaluate transmission expansion plan and resource plan implementation.~~
   - ~~Coordinate projects requiring transmission outages that can impact reliability and firm transactions.~~

~~13.~~4. Coordinate with adjoining Planning Coordinators to develop interconnection models with appropriate loads, resources, and System topology. ~~so that system models and resource and transmission expansion plans take into account modifications made to adjacent Planning Coordinator areas.~~

5. Evaluate and report on the performance of the consolidated Transmission assessments. ~~Develop and maintain transmission and resource (demand and capacity) system models to evaluate transmission system performance and resource adequacy.~~

~~14.~~6. Evaluate interconnection reliability concerns among affected Planning Coordinators.

Planning Coordinator

Definition

The ~~functional~~ responsible entity that coordinates~~, facilitates,~~ and integrates ~~and evaluates (generally one year and beyond)~~ transmission ~~f~~Facilit~~y~~ies and service plans, ~~and~~ resource plans, and Protection Systems.[8] ~~within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas.~~

Introduction to the Planning Coordinator

By its very nature, BES planning involves multiple entities. Since all electric systems within an integrated network are electrically connected, whatever one system does can affect the other systems. The Planning Coordinator is responsible for coordinating the assessment~~ing~~ of the BES within its ~~the longer-term reliability of its~~ Planning Coordinator area. The PC assessment includes the collection of Transmission assets over which the Planning Coordinator is responsible for coordinating planning ("PC Area"). The PC Area is normally comprised of more than one Transmission Planner; however, ~~While~~ the area under the purview of a Planning Coordinator may include as few as one Transmission Planner. ~~and one Resource Planner,~~ ~~t~~The Planning Coordinator's scope of activities is intended to span a broader area that may include BES assets of multiple Transmission Planners. All BES Facilities should be assigned to a Transmission Planner and to a Planning Coordinator, so that there are no gaps in the assessment of the BES. ~~may include extended coordination with integrated Planning Coordinators' plans for adjoining areas beyond individual system plans. By its very nature, Bulk Electric System planning involves multiple entities. Since all electric systems within an integrated network are electrically connected, whatever one system does can affect the other systems.~~ Planning Coordinators work through a variety of processes ~~mechanisms~~ to conduct facilitated, coordinated, joint, centralized, or regional planning activities to the extent that all portions of the interconnected BES ~~network areas with little or no ties to others' areas, such as interconnections,~~ are completely coordinated for planning activities.

Relationships with Other Functional Entities

1. Establish ~~Coordinates~~ power system modeling data requirements in conjunction with interconnected ~~and collects data for system modeling from~~ Transmission Planners~~, Resource Planner,~~ and other Planning Coordinators.
2. Collect data for power system modeling and assessments from the Transmission Planner.
3. ~~2.~~ Determine ~~Coordinates~~ transfer capability ~~(generally one year and beyond)~~ with ~~Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and~~ neighboring Planning Coordinators.
4. ~~3.~~ Exchange information on ~~Coordinates~~ Contingencies, criteria, System Operating Limits (SOLs), Remedial Action Schemes (RAS), automatic load-shedding schemes, and plans with the Reliability Coordinator and other Planning Coordinators ~~on reliability issues~~.
5. ~~4.~~ Assess the performance of the Transmission system, in coordination with Transmission Planners ~~Receives plans from Transmission Planners and Resource Planners~~.

~~5. Collects information including:~~

- ~~Transmission facility characteristics and ratings from the Transmission Owners, Transmission Planners, and Transmission Operators.~~
- ~~Demand and energy forecasts, capacity resources, and demand response programs from~~

[8] Definition of Planning Authority from the NERC Glossary of Terms (as of May 15, 2016). In the Glossary, Planning Coordinator and Planning Authority are defined interchangeably.

~~Load-Serving Entities, and Resource Planners.~~

~~. Generator unit performance characteristics and capabilities from Generator Owners.~~

~~. Long-term capacity purchases and sales from Transmission Service Providers.~~

~~10.~~6. Collect~~s~~ and review~~s~~ reports on ~~t~~Transmission, loads and resource~~s plan implementation~~ from ~~Resource Planners and~~ Transmission Planners.

~~11. Submits and coordinates the plans for the interconnection of facilities to the Bulk Electric System within its Planning Coordinator area with Transmission Planners and Resource Planners and adjacent Planning Coordinator areas, as appropriate.~~

~~12. Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system.~~

~~13.~~7. Facilitate~~s~~ the integration of the respective plans of the ~~Resource Planners and~~ Transmission Planners within the Planning Coordinator area, and adjacent Planning Coordinator areas, as appropriate.

a. Review~~s~~ the integrated plan with respect to established reliability needs considering the impact on and by adjoining ~~s~~Systems.

b. In coordination with the ~~Resource Planners and~~ Transmission Planners, facilitate~~s~~ the development of alternative solutions for plans that do not meet those reliability performance criteria ~~needs~~.

Transmission Planning and Transmission Planner

Transmission Planning

Tasks

1. Develop and ~~M~~maintain~~ and develop, in cooperation with adjacent and overlapping Transmission Planners,~~ methodologies, criteria and tools for the analysis and simulation of the ~~t~~Transmission systems~~ in the evaluation and development of transmission expansion plans related to resource adequacy plans~~.

2. ~~Define, consolidate and collect or d~~Develop, acquire and validate~~, in cooperation with adjacent and overlapping Transmission Planners,~~ information required for Transmission assessments~~planning purposes~~ including:

    a. Transmission ~~f~~Facility characteristics and ~~r~~Ratings.

    b. Demand and Electrical ~~e~~Energy forecasts, capacity resources, and Demand-Side Management (DSM) ~~demand response~~ programs.

    c. Generator unit performance characteristics and capabilities.

    d. Commitments for firm Transmission Interchange.~~Long-term capacity purchases and sales~~

    e. Load forecasts and generation dispatch scenarios.

3. Develop and ~~M~~maintain ~~transmission~~ power system models (steady state, dynamics, and short circuit) necessary for the assessment of Transmission system ~~to evaluate Bulk Electric System~~ performance for identified scenarios.

4. Exchange information with other ~~Coordinate with adjacent and overlapping~~ Transmission Planners and the Planning Coordinator to achieve an interconnected~~ so that system~~ model~~s and resource and transmission expansion plans take into account modifications made to adjacent and overlapping Transmission Planner areas~~.

5. ~~Evaluate, develop, document, and report on expansion plans for the Transmission Planner area.~~ Assess the performance of the Transmission system with the anticipated topology and scenarios of loads and resources~~ whether the integrated plan meets reliability needs, and, if not, report on potential network conditions or configurations that do not meet performance requirements and provide potential alternative solutions to meet performance requirements~~.

    ~~. Evaluate the plans that are in response to long-term (generally one year and beyond) customer requests for transmission service.~~

    ~~. Evaluate and plan for all requests required to integrate new (End-use Customer, generation, and transmission) facilities into the Bulk Electric System.~~

    ~~. Determine transfer capability values (generally one year and beyond) as appropriate.~~

    ~~. Monitor, evaluate and report on transmission expansion plan and resource~~

~~plan implementation.~~

~~. Coordinate projects requiring transmission outages that can impact reliability and firm transactions.~~

~~5. Notify Generation Owners, Resource Planners, Transmission Planners and Transmission Owners of any planned transmission changes that may impact their facilities.~~

~~5. Define system protection and control needs and requirements, including special protection systems (remedial action schemes), to meet reliability needs.~~

Transmission Planner

Definition

The ~~functional~~ 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 ~~a Transmission Planner~~ area.[9]

Introduction to the Transmission Planner

The Transmission Planner is responsible for assessing the long~~er-~~ term (generally one year and beyond) Transmission system performance within ~~reliability of~~ its Transmission Planner area. The TP assessment includes the collection of Transmission assets over which the Transmission Planner is responsible for planning ("TP Area"). By its very nature, BES~~ulk Electric System~~ planning involves multiple entities. Since all electric ~~s~~Systems within an integrated network are electrically connected, changes planned in ~~whatever~~ one part of the ~~s~~System ~~does~~ can affect the other parts of the ~~s~~System~~s~~. Transmission Planners coordinate their plans with the adjoining Transmission Planners to assess impact on or by those plans. The area under the purview of a Transmission Planner may include one or more Resource Planner areas. ~~and overlap one or more adjacent Transmission Planners.~~ All BES Facilities should be under the purview of at least one Transmission Planner.

Relationships with Other Functional Entities

1. Coordinate~~s~~ and collect~~s~~ data (steady state, dynamics, and short circuit) for power system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, Resource Planners~~, other Transmission Planners,~~ Transmission Owners, ~~and~~ Transmission Service Providers, and other Transmission Planners.

2. Collect~~s~~ information including:

   a. Transmission facility characteristics and ~~r~~Ratings from the Transmission Owners, Transmission Planners, and Transmission Operators.

   b. Demand and Electrical ~~e~~Energy forecasts, capacity resources, and ~~d~~Demand-Side Management ~~response~~ programs from Load-Serving Entities, and Resource Planners.

   c. Generator unit performance characteristics and capabilities from Generator Owners.

   d. Commitments for firm Transmission Interchange ~~Long-term transmission capacity purchases and sales~~ from Transmission Service Providers.

3. Inform~~s~~ Resource Planners and other Transmission Planners of the methodologies and tools for the simulation of the ~~t~~Transmission system.

~~4. Coordinates with Resource Planners and other Transmission Planners on Bulk Electric System expansion plans.~~

~~5.~~4. Coordinate~~s the evaluation of~~ BES~~ulk Electric System~~ expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.

~~6.~~5. Report~~s~~ on and coordinate~~s~~ its BES~~ulk Electric System~~ expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service

[9] Definition of Transmission Planner from the NERC Glossary of Terms (as of May 15, 2016).

Providers, Transmission Owners, Transmission Operators and Reliability Assurers.

~~7.~~6. Notif~~ies~~y other Transmission Planners, Transmission Owners, Transmission Operators and other entities that may be impacted ~~of~~by any planned B~~ulk Electric System~~ES changes.

~~8.~~7. Coordinate~~s~~ with Distribution Providers, Transmission Owners, Generator Owners and Load-Serving Entities in the evaluation and plans for all requests required to integrate new (~~E~~end-use ~~C~~customer, generation, and ~~t~~Transmission) ~~f~~Facilities into the B~~ulk Electric System~~ES.

~~9.~~8. Submit~~s~~ and coordinate~~s~~ the plans for the interconnection of ~~f~~Facilities to the B~~ulk Electric System~~ES within its Transmission Planner area with other Transmission Planners and ~~Resource Planners~~the Planning Coordinator, as appropriate.

~~10.~~9. Coordinate~~s~~ and develop~~s~~ ~~t~~Transfer ~~c~~Capability values with other Transmission Planners, Reliability Coordinators, Transmission Operators, Transmission Owners, ~~and~~ Transmission Service Providers, and the Planning Coordinator.

~~11.~~10. Coordinate~~s~~ with Transmission Owners and Generator Owners to define system protection and control needs and requirements, including ~~special protection systems (r~~Remedial ~~a~~Action ~~s~~Schemes~~),~~ to meet reliability needs.

11. Receive~~s~~ maintenance schedules and construction plans from Transmission Operator or Transmission Owner for input into and evaluation of B~~ulk Electric System~~ES expansion plans.

Resource Planning and Resource Planner

Resource Planning

Tasks

~~1. Consider generation capacity from resources both within and outside of the Resource Planner area for assessing resource adequacy.~~

~~2. Monitor and report, as appropriate, on its resource plan implementation.~~

~~3.~~1. ~~Develop and maintain resource (demand and capacity) models~~ Acquire or develop the tools needed to evaluate long-term resource ~~a~~Adequacy for a specific set of loads.

~~4.~~2. ~~Collect~~ Acquire or develop the data and information required for performing periodic resource ~~a~~Adequacy ~~purposes~~assessments.~~, including:~~

- ~~demand and energy forecasts, capacity resources, and demand response programs,~~
- ~~generator unit performance characteristics and capabilities, and~~
- ~~long-term capacity purchases and sales and~~
- ~~transmission (interface) limits.~~

3. Determine the reliability criteria used as the basis for assessing long-term resource Adequacy.

~~9.~~4. Perform periodic resource Adequacy assessments and document the results.

5. Evaluate future ~~, develop, document, and report on a~~ resource alternatives~~. adequacy plan for its portion of the Transmission Planner and Planning Coordinator area~~.

~~10.~~6. Create and periodically update a long-term resource plan~~Assist in the evaluation of the deliverability of resources~~.

Resource Planner

Definition

The ~~functional~~ 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 ~~Resource Planner~~ area.[10]

Relationships with Other Functional Entities

1. Collect data and information required for performing periodic resource Adequacy assessments from one or more of the following entities as necessary: Load-Serving Entity, Generator Owner, Generator Operator, Transmission Planner, Planning Coordinator, and Transmission Service Provider.

~~1.~~2. Provide long-term ~~Coordinates the~~ resource plan information ~~models with~~ to the ~~its~~ Transmission Planner for power system modeling and Planning Assessments~~Planning Coordinator~~.

~~2.~~3. Receive information from~~Coordinates with~~ the ~~Transmission Owners and~~ Transmission Planners regarding submitted resource plan ~~on the~~ deliverability ~~of resources to customers~~.

~~3.~~4. Provide resource plan recommendations to the affiliated ~~Coordinates with and collects data for resource planning from the Load-Serving Entities,~~ Generator Owner and Load-Serving Entity~~s, Generator Operators, Transmission Planners, Transmission Operators, Interchange Coordinators, and Reliability Assurers~~.

~~4.~~5. Coordinate~~s~~ with Transmission Planners~~,~~ and Transmission Service Providers~~, Reliability Coordinators, and Planning Coordinators~~ on resource ~~adequacy~~ plans.

~~5. Coordinates with adjoining Resource Planners within the Planning Coordinator area to avoid the double-counting of resources.~~

~~6. Reports its resource plan to the Transmission Planner and Planning Coordinator for evaluation and compliance with Reliability Standards.~~

~~7.~~6. Assess alternative ~~Works~~ plans with ~~the Planning Coordinator and~~ Transmission Planners to identify potential alternative ~~transmission~~ solutions to meet ~~Resource Planner~~resource Adequacy ~~plans~~requirements.

~~8. Applies methodologies and tools for the analysis and development of resource adequacy plans from the Planning Coordinator.~~

[10] Definition of Resource Planner from the NERC Glossary of Terms (as of May 15, 2016).

Reliability Operations and Reliability Coordinator

Reliability Operations

Tasks

1. Monitor all reliability-related parameters within the reliability area, including generation dispatch and ~~generation/transmission~~ maintenance plans for generation and Transmission.
2. Identify, communicate, and direct actions if necessary to relieve reliability threats and limit violations in the reliability area.
3. Develop Interconnection Reliability Operating Limits (to protect from instability and Cascading).
4. Assist in determining Interconnected Operations Services (IOS) ~~reliability-related services~~ requirements for:
    a. balancing generation and load,[11] and
    b. ~~transmission~~ reliability of Transmission ~~(*e.g.*, reactive requirements, location of operating reserves).~~
5. Perform reliability analysis (actual and ~~c~~Contingency) for the reliability area.
6. Direct revisions to ~~t~~Transmission maintenance plans as permitted by ~~a~~Agreements.
7. Direct revisions to generation maintenance plans as permitted by ~~a~~Agreements.
8. Direct implementation of emergency[12] procedures including load-shedding.
9. Direct and coordinate restoration of the BES for its RC Area~~system restoration~~.
10. Curtail Confirmed Interchange that adversely impacts reliability.
11. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.

~~11.~~12. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

[11] The Glossary definition of "Load" is not appropriate because the Glossary definition refers to end-use customer or end-use device; the Glossary definition does not incorporate the concept of quantity.

[12] The Glossary definition of "Emergency" is not appropriate because the definition is limited in application to the BES. In this context, the RC may encounter an emergency situation that is broader than the circumstances described in the Glossary definition.

Reliability Coordinator

Definition

~~The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area.~~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.[13]

Introduction to the Reliability Coordinator

The Reliability Coordinator maintains the Real-time operating reliability of its Reliability Coordinator Area and in coordination with its neighboring Reliability Coordinator's ~~w~~Wide-~~a~~Area view. Wide-Area view means the entire Reliability Coordinator area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.[14] The ~~w~~Wide-~~a~~Area view includes situational awareness of its neighboring Reliability Coordinator Areas. ~~Its scope includes both transmission and balancing operations~~The RC ~~, and it~~ has the authority to direct other functional entities to take certain actions to ensure that its Reliability Coordinator Area operates reliably. Its scope includes both:

1. **Transmission operations**. With respect to transmission operations, the Reliability Coordinator and Transmission Operator have similar roles, but different scopes. The Transmission Operator directly maintains reliability for its Transmission Operator Area~~own defined area~~. However, the Reliability Coordinator also maintains reliability, in concert with the other Reliability Coordinators, for the Interconnection as a whole. Thus, the Reliability Coordinator needs a ~~"w~~Wide-~~a~~Area~~"~~ view that reaches beyond its boundaries to enable it to operate within Interconnection Reliability Operating Limits. The Transmission Operator may or may not have this ~~"w~~Wide-~~-a~~Area~~"~~ view, but the Reliability Coordinator does have it. The Reliability Coordinator may direct a Transmission Operator within its Reliability Coordinator Area to take whatever action is necessary to ensure that Interconnection Reliability Operating Limits are not exceeded.

2. **Balancing operations**. The Reliability Coordinator ensures that the generation-~~d~~Demand balance is maintained within its Reliability Coordinator Area, which, in turn, ensures that the Interconnection frequency remains within acceptable limits. The Balancing Authority has the responsibility for generation-~~d~~Demand-~~i~~Interchange balance in the Balancing Authority Area. The Reliability Coordinator may direct a Balancing Authority within its Reliability Coordinator Area to take whatever action is necessary to ensure that this balance does not adversely impact reliability.

Relationships with Other Functional Entities

Ahead of Time

1. Coordinate~~s~~ with other Reliability Coordinators, Transmission Planners, and Transmission

[13] Definition of Reliability Coordinator from the NERC Glossary of Terms (as of May 15, 2016).

[14] Definition of "Wide-area" from the NERC Glossary of Terms (as of May 15, 2016).

Service Providers on ~~t~~Transmission system[15] limitations.

2. Receive~~s~~ facility[16] and operational data from Generator Operators, Distribution Providers, Load-Serving Entities, Transmission Owners, Generator Owners, and Transmission Operators.
3. Receive~~s~~ generation dispatch from Balancing Authorities and issue~~s~~ dispatch adjustments to Balancing Authorities to prevent exceeding limits within the Reliability Coordinator Area (if not resolved through market mechanisms).
4. Receive~~s~~ integrated operational plans from Balancing Authorities for reliability analysis of Reliability Coordinator Area.
5. Receive~~s~~ ~~t~~Transmission and generation maintenance plans from Transmission Owners and Generator Owners, respectively, for reliability analysis.
6. ~~Develops~~Provide Interconnection Reliability Operating Limits (IROLs)~~, based on Transmission Owners' and Generator Owners' specified equipment ratings, and provides them~~ to those functional entities with a reliability-related need~~Transmission Operators~~.
7. Assist~~s~~ Transmission Operators in calculating and coordinating System Operating Limits.
8. Provide~~s~~ reliability analyses to Transmission Operators, Generator Operators and Balancing Authorities in its area as well as other Reliability Coordinators.
9. Direct~~s~~ Generator Owners and Transmission Owners to revise generation and ~~t~~Transmission maintenance plans that are adverse to reliability.
10. Receive~~s~~ balancing information from Balancing Authorities for monitoring.
11. Receive~~s~~ final approval or denial of Arranged Interchange from Interchange Coordinator.

~~12. Provide IROLs and TTC to the Transmission Service Provider for ATC calculation.~~

~~13.~~12. Develops operating agreements or procedures with Transmission Owners.

~~14.~~13. Coordinate~~s~~ with Transmission Operators on ~~system~~ restoration plans, contingency[17] plans and Interconnected Operations Services (IOS)~~reliability-related services~~.

Real-time

~~15.~~14. Coordinate~~s~~ reliability processes and actions with and among other Reliability Coordinators.

~~16.~~15. Receive~~s~~ Real-time operational information from Balancing Authorities, Interchange Coordinators and Transmission Operators for monitoring.

~~17.~~16. Issue~~s~~ reliability alerts to Generator Operators, Transmission Operators, Transmission Service Providers, Balancing Authorities, Interchange Coordinators, Regional Entities and NERC.

~~18.~~17. Issue~~s~~ corrective actions and ~~e~~Emergency procedure~~s~~ directives ~~(*e.g.*, curtailments or load shedding)~~ to Transmission Operators, Balancing Authorities, Generator Operators, Distribution Providers, and Interchange Coordinators.

[15] The Glossary definition of "System" is not appropriate in this context because the limitations may not always include a combination of generation, transmission, *and* distribution.
[16] The Glossary definition of "Facility" is not appropriate because the definition is limited in application to BES Elements. In this context, the intent is to have broader application to include non-BES elements (*e.g.*, industrial equipment).
[17] The Glossary definition of "Contingency" is not appropriate because application in this context is not limited to power system contingency (*i.e.,* N-1 event); in this context, intended to have broader meaning.

~~19.~~18. Specif~~ies~~y reliability–related requirements to Balancing Authorities.

~~20.~~19. Receive~~s~~ verification of ~~e~~Emergency procedures from Balancing Authorities.

~~21.~~20. Receive~~s~~ notification of Confirmed Interchange changes from Balancing Authorities.

~~22.~~21. Order~~s~~ re-dispatch of generation by Balancing Authorities.

~~23.~~22. Direct~~s~~ use of flow control devices by Transmission Operators.

~~24.~~23. Respond~~s~~ to requests from Transmission Operators to assist in mitigating equipment overloads.

Balancing and Balancing Authority

Balancing

Tasks

1. Control any of the following combinations within a Balancing Authority Area:
    a. ~~Load and generation (an isolated system)~~Demand and resource
    b. ~~Load~~ Demand and Confirmed Interchange
    c. Generation and Confirmed Interchange
    d. Generation, ~~load~~Demand, and Confirmed Interchange
2. Calculate ~~a~~Area ~~c~~Control ~~e~~Error (ACE) within the reliability area.
3. Operate in the Balancing Authority Area to maintain Demand and resource~~load-interchange-generation~~ balance.
4. Review generation commitments, dispatch, and ~~load~~ Demand forecasts.
5. Formulate an operational plan (*e.g.,* generation commitment, outages~~, etc.~~) for reliability evaluation.
6. Approve Arranged Interchange from ~~r~~Ramping ability perspective.
7. Implement Confirmed Arranged Interchange.
8. Operate the Balancing Authority Area to contribute to Interconnection frequency.
9. Monitor and report control performance and disturbance[18] recovery.
10. Provide balancing and energy accounting (including hourly checkout of Confirmed Arranged Interchange, Implemented Interchange and actual ~~i~~Interchange), and administer inadvertent energy paybacks.
11. Determine needs for Interconnected Operations Services~~reliability-related services~~.
12. Deploy Interconnected Operations Services (IOS)~~reliability-related services~~.
13. Implement ~~e~~Emergency procedures.
14. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.
15. ~~14.~~15. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

[G] The Glossary definition of “Contingency” is not appropriate because the definition is too broad.

Balancing Authority

Definition

The ~~functional~~ responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports ~~contributes to~~ Interconnection frequency in real time.[19]

Relationships with Other Functional Entities

Ahead of Time

1. Receive generator Facility plans from Generator Operators within the Balancing Authority Area.
2. Receive operational data from Generator Operators within the Balancing Authority Area.
3. ~~1.~~ Receive~~s~~ operating and availability status of generating units ~~and operational plans and commitments~~ from Generator Operators ~~(including annual maintenance plans)~~ within the Balancing Authority Area.
~~2. Receives annual maintenance plans from Generator Owners within the Balancing Authority Area.~~
4. ~~3.~~ Receive~~s~~ reliability evaluations from the Reliability Coordinator.
~~4. Receives final approval or denial of a request for an Arranged Interchange from the Interchange Coordinators.~~
5. Compile~~s~~ ~~load~~Demand forecasts from Load-Serving Entities.
6. Develop~~s~~ ~~a~~Agreements with adjacent Balancing Authorities for ACE calculation parameters.
7. Submit~~s~~ integrated operational plans to the Reliability Coordinator for reliability evaluation and provides balancing information to the Reliability Coordinator for monitoring.
8. ~~Confirms~~ Receive Arranged Interchange from~~with~~ Interchange Coordinators.
9. ~~Confirms~~ Send approval or denial of Arranged Interchange based on meeting ~~r~~Ramping requirements ~~capability~~ to ~~with~~ Interchange Coordinators.
10. ~~9.~~ Receive notice of final approval or denial of Arranged Interchange becoming Confirmed Interchange from the Interchange Coordinator.
11. ~~10.~~ Implement~~s~~ generator commitment and dispatch schedules from the Load-Serving Entities ~~and Generator Operators~~ who have arranged for ~~generation~~ resources within the Balancing Authority Area.
12. ~~11.~~ Acquires Interconnected Operations Services (IOS) ~~reliability-related services~~ from Generator Operator.
13. ~~12.~~ Receive~~s~~ dispatch adjustments from Reliability Coordinators to prevent exceeding limits.
14. Receives generator information from Generator Owners including unit maintenance schedules and retirement plans.
15. ~~13.~~ Receive reports on frequency regulating equipment from Generator Operators within the Balancing Authority Area.

[19] Definition of Balancing Authority from the NERC Glossary of Terms (as of May 15, 2016).

~~14.~~16. Receives~~s~~ information from Load-~~-~~Serving Entities on self-provided Interconnected Operations Services (IOS) ~~reliability-related services~~.

~~15.~~17. Coordinates~~s~~ ~~system~~ restoration plans (*i.e.*, any combination of generation, Transmission or distribution components) with the Transmission Operator.

~~16.~~18. Provides~~s~~ ~~generation~~ resource dispatch to Reliability Coordinators.

Real-time

~~17.~~19. Coordinates~~s~~ use of Interruptible Demand ~~controllable loads~~ with Load-Serving Entities ~~(*i.e.*, interruptible load that has been bid in as a reliability-related service or has agreed to participate in voluntary load shedding program under resource/reserve deficiency situations)~~.

~~18.~~20. Receives~~s~~ loss allocation from Transmission Service Providers (for repayment with in-kind losses).

~~19.~~21. Receives~~s~~ Real-time operating information from the Transmission Operator, adjacent Balancing Authorities and Generator Operators.

~~20.~~22. Receives~~s~~ operating information from Generator Operators.

~~21.~~23. Provides~~s~~ Real-time operational information for Reliability Coordinator monitoring.

~~22.~~24. Receives~~s~~ reliability alerts from Reliability Coordinator.

~~23.~~25. Comply~~ies~~ with reliability-related requirements (*e.g.*, reactive requirements, location of operating reserves) specified by Reliability Coordinator.

~~24.~~26. Verify~~ies~~ implementation of ~~e~~Emergency procedures to Reliability Coordinator.

27. Inform~~s~~ Reliability Coordinator and Interchange Coordinators of Confirmed Interchange changes (*e.g.*, due to Demand ~~generation~~ or resource~~load~~ interruptions) involving its Balancing Authority Area.

~~25.~~28. Receive Confirmed Interchange revisions (including Curtailments) from Interchange Coordinators.

~~26.~~29. Direct~~s~~ resources (Generator Operators and Load-Serving Entities) to take action to ensure balance in ~~r~~Real-~~-~~time.

~~27.~~30. Request ~~Directs~~ Transmission Operator (or Distribution Provider) to reduce voltage to lower Demand or shed load if needed to ensure balance within its Balancing Authority Area.

~~28.~~31. Direct~~s~~ Generator Operators to implement re-dispatch for congestion management as directed by the Reliability Coordinator.

~~29.~~32. Implements corrective actions and ~~e~~Emergency procedures as directed by the Reliability Coordinator.

~~30.~~33. Implement~~s~~ ~~system~~ restoration plans (*i.e.*, any combination of generation, Transmission or distribution components) as directed by the Transmission Operator.

~~31.~~34. Direct~~s~~ Transmission Operator to implement flow control devices.

~~31. Receives information of Implemented Interchange and Confirmed Interchange curtailments from Interchange Coordinator.~~

After the hour

~~32.~~35. Confirm~~s~~ Implemented Interchange with Confirmed Interchange provided by the Interchange Coordinators after the hour for "checkout."

36. Confirm~~s~~ Implemented Interchange and Confirmed Interchange with adjacent Balancing Authorities

after the hour for "checkout."

~~33.~~37. Request record of individual Confirmed Interchange from Interchange Coordinator.

Market Operations and Market Operator (Resource Integrator)

Market Operations

Tasks

1. The m~~M~~arket ~~O~~operations function, its tasks, and the interrelationships with other entities are included in the Functional Model only as an interface point of reliability ~~F~~functions with commercial functions.

Market Operator (Resource Integrator)

Definition

The market entity whose interrelationships with other entities are included in the Functional Model only as an interface point of reliability functions with commercial functions.

Relationships with Other Functional Entities

Market o~~O~~perator tasks and relationships are specific to a particular market design and will depend on the market structure over which the ~~M~~market ~~O~~operator presides.

Transmission Operations and Transmission Operator

Transmission Operations

Tasks

1. Monitor and provide telemetry (as needed) of all reliability-related parameters within the reliability area.
2. Monitor the status of, and deploy, facilities[20] classed as ~~t~~Transmission assets, which may include the ~~t~~Transmission lines connecting a generating plant to the ~~t~~Transmission system, associated protective relaying systems and Remedial Action Schemes~~Special Protection Systems~~.
3. Develop ~~s~~System limitations (*e.g.*, ~~, such as~~ System Operating Limits) ~~and Total Transfer Capabilities,~~ and operate within those limits.
4. Develop and implement ~~e~~Emergency procedures.
5. Develop and implement ~~s~~System restoration plans.
6. Operate within established Interconnection Reliability Operating Limits.
7. Perform reliability analysis ~~(actual and contingency)~~ for the Transmission Operator Area.
8. Adjust Real Power, Reactive Power and voltage ~~flow control devices within the transmission area~~ to maintain reliability.

~~9. Deploy reactive resources to maintain transmission voltage within defined limits.~~

~~10.~~9. Determine the Transmission capability that supports the Reliable Operation of the Transmission Operator Area.

~~11.~~10. Operate or direct the operation of Transmission Facilities in its TOP Area.

11. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.

12. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

[20] The Glossary definition of "Facility" is not appropriate because the definition is limited in application to BES Elements. In this context, the intent is to have broader application to include responsibilities for non-BES elements.

Transmission Operator

Definition

The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission Facilities.[21] ~~The functional entity that ensures the Real-time operating reliability of the transmission assets within a Transmission Operator Area.~~

Introduction to the Transmission Operator

The Transmission Operator is responsible for the Real-time operating reliability of the ~~t~~Transmission assets under its purview, which is referred to as the Transmission Operator Area. The Transmission Operator has the authority to take certain actions to ensure that its Transmission Operator Area operates reliably.

The Transmission Operator and Reliability Coordinator have similar roles with respect to the reliability of the ~~t~~Transmission system~~operations~~, but have different responsibilities ~~scopes~~. The Transmission Operator shares a role in monitoring the Transmission system with ~~scope is narrower than~~ the Reliability Coordinator and additionally, has the operational responsibility for the Transmission system area under its purview.~~and the Transmission Operator does not necessarily "see" very far beyond its own boundaries. Therefore, t~~ The Transmission Operator can calculate System Operating Limits, but does not necessarily have the Wide-area view of the Reliability Coordinator ~~will not necessarily~~ necessary to calculate Interconnection Reliability Operating Limits.~~, which requires the wider scope of the Reliability Coordinator.~~

Relationships with Other Functional Entities

Ahead of Time

1. Coordinate~~s~~ restoration plans with Reliability Coordinator, Transmission Operators, Balancing Authorities, and Distribution Providers.
2. Receive~~s~~ maintenance requirements and construction plans and schedules from the Transmission Owners and Generation Owners.
3. Receive~~s~~ Interconnection Reliability Operating Limits as established by the Reliability Coordinator.
4. Receive~~s~~ reliability evaluations from the Reliability Coordinator.
5. Develop~~s~~ agreements (Operating Plans, procedures, and processes) with adjacent Transmission Operators ~~for joint transmission facilities~~.
6. Define~~s~~ Total Transfer Capabilities and System Operating Limits based on facility[22] information provided by the Transmission Owners and Generator Owners and assistance from Reliability Coordinator.
7. Arrange~~s~~ for Interconnected Operations Services (IOS) ~~reliability-related services~~ from Generator Operators (*e.g.*, voltage schedules, VAR Demand schedule).
8. Develop~~s~~ contingency plans, and monitors operations of the ~~t~~Transmission facilities within the Transmission Operator Area control and as directed by the Reliability Coordinator.
9. Provide~~s~~ facility and operating information to the Reliability Coordinator.
10. Provide~~s~~ to the Transmission Planner information on the capability to ~~c~~Curtail (reduce) and shed load during ~~e~~Emergencies.

[21] Definition of Transmission Operator from the NERC Glossary of Terms (as of May 15, 2016).

[22] The Glossary definition of "Facility" is not appropriate because the definition is limited in application to BES Elements. In this context, the intent is to have broader application to include responsibilities for non-BES elements.

11. Provide~~s~~ Total Transfer Capabilities, ~~and~~ System Operating Limits, and methodology for calculating ~~to, and coordinates~~ Available Transfer Capability for respective Transmission paths to~~with,~~ Transmission Service Provider.

12. Receive~~s~~ operating and availability status of generating units from Generator~~ion~~ Operators including status of automatic voltage regulators and power system stabilizers.

~~12.~~13. Receive operational data from Generator Operators.

~~13.~~14. Develop~~s~~ operating agreements or procedures with Transmission Owners.

Real-time

~~14.~~15. Coordinates load shedding with, or as directed by, the Reliability Coordinator.

~~15.~~16. Provide~~s~~ Real-time operations information to the Reliability Coordinator and Balancing Authority.

~~16.~~17. Notify~~ies~~ Generator Operators of ~~t~~Transmission system problems (*e.g.*, voltage limitations or equipment overloads that may affect generator operations).

~~17.~~18. Request~~s~~ Reliability Coordinator to assist in mitigating equipment overloads. (*e.g.*, re-dispatch, ~~t~~Transmission loading relief).

~~18.~~19. Deploy~~s~~ reactive resources from Transmission Owners, ~~and~~ Generator Owners, and Distribution Providers to maintain acceptable voltage profiles.

~~19.~~20. Direct~~s~~ Distribution Providers to shed load if needed to ensure reliability within the Transmission Operator Area.

~~20.~~21. Implement~~s~~ flow control device operations for those ties under the Transmission Operator's purview as directed by the Balancing Authorities or Reliability Coordinator.

~~21.~~22. Receive~~s~~ reliability alerts from Reliability Coordinator.

~~22.~~23. Direct~~s~~ Balancing Authorities and Distribution Providers to implement system restoration plans.

~~23.~~24. Receive Real-time operating information from Generator Operators.

Interchange and Interchange Coordinator

Interchange

Tasks

1. Receive completed Request for Interchange (RFI) (*i.e.*, valid source and sink, Transmission arrangements) ~~an Arranged Interchange~~.
2. Transition RFI to ~~Ensure an~~ Arranged Interchange ~~is balanced and valid (Balancing Authority and Transmission Service Provider validation of sources and sinks, transmission arrangements, reliability-related services, etc.)~~.
3. Forward Arranged Interchange to entities for ~~Coordinate (*i.e.*, collect and consolidate)~~ approval, change, or~~and~~ denial ~~requests for an Arranged Interchange to become Confirmed Interchange~~. ~~Approvals may be explicit or by exception.~~
4. Collect approvals and denials ~~Receive confirmations~~ of requested Arranged Interchange.
5. Communicate status of an Arranged Interchange that becomes Confirmed Interchange or otherwise.
6. Communicate Confirmed Interchange information to the appropriate reliability assessment tools (*e.g.*, the interchange distribution calculator in the Eastern Interconnection).
7. Submit Arranged Interchange for Curtailments and re-dispatch implementation requests.

~~7.~~8. Maintain record of an individual Confirmed Interchange.

~~8.~~9. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.

~~9.~~10. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

Interchange Coordinator

Definition

The ~~functional~~ responsible entity that authorizes ~~ensures communication of Arranged Interchange for reliability evaluation purposes and coordinates~~ implementation of valid and balanced Interchange Schedules ~~Confirmed Interchange~~ between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.[23]

Relationships with Other Functional Entities

Ahead of Time

1. Receive~~s~~ Requests for ~~Arranged~~ Interchange from Generation Owner, Purchasing-Selling Entity, and Load-~~-~~Serving Entity~~ies~~.

2. Submit~~s~~ ~~request for an~~ Arranged Interchange to become Confirmed Interchange to the Balancing Authorities and Transmission Service Providers for approvals.

3. Receive~~s~~ approval or denial from Transmission Service Providers of ~~t~~Transmission arrangement(s) for Arranged Interchange.

4. Receive~~s~~ approval or denial from Balancing Authorities of the ability to meet ~~r~~Ramping requirements for submitted Arranged Interchange.

~~4.~~5. Receives approval from Generation Owners, Purchase-Selling Entities, or Load-Serving Entities for any revised Arranged Interchange.

~~5.~~6. Communicate~~s~~ final approval or denial of a request for an Arranged Interchange to become Confirmed ~~i~~Interchange to the Reliability Coordinator, Balancing Authorities, Transmission Service Providers, Generation Owners, ~~and~~ Purchasing-Selling Entities, and Load-Serving Entities for implementation ~~and NERC identified reliability analysis services~~.

Real-time

7. Receive reliability alerts from the Reliability Coordinators.

~~6.~~8. Receive~~s~~ ~~c~~Curtailments and re-dispatch implementation requests from Reliability Coordinators and submits ~~for an~~ Arranged Interchange.

~~7.~~9. Receive~~s~~ information on Confirmed Interchange interruptions from the Balancing Authorities and communicates the Confirmed Interchange status to Balancing Authorities, Transmission Service Providers, Reliability Coordinators, Generation Owner, and Purchasing-Selling Entities, and ~~/~~Load- Serving Entities.

~~8.~~10. Inform~~s~~ Reliability Coordinators, Balancing Authorities, Transmission Service Providers, Generation Owners, Purchasing-Selling Entities, and~~/~~ Load-Serving Entities~~, Reliability Coordinators, and Balancing Authorities~~ of Confirmed Interchange revisions (including ~~c~~Curtailments).

After the hour

~~9.~~11. ~~Maintains and p~~Provide~~s~~ a record of individual Confirmed Interchange to requesting ~~for which it coordinated with the~~ Balancing Authorities.

[23] Definition of Interchange Authority from the NERC Glossary of Terms (as of May 15, 2016). The Glossary uses the term "Interchange Authority" whereas the Functional Model uses the term "Interchange Coordinator."

12. Coordinates~~s~~ Confirmed Interchange with Balancing Authorities after the hour for “checkout.”

Transmission Service and Transmission Service Provider

Transmission Service

Tasks

1. Receive ~~t~~Transmission ~~s~~Service requests and process each request for service according to the requirements of the tariff.
    a. Maintain commercial interface for receiving and confirming requests for ~~t~~Transmission ~~s~~Service according to the requirements of the tariff (*e.g.*, OASIS).
2. Determine and post available transfer ~~capability~~ capacity values.
3. Approve or deny ~~t~~Transmission ~~s~~Service requests.
4. Approve or deny Arranged Interchange from ~~t~~Transmission ~~s~~Service arrangement perspective.
5. Allocate ~~t~~Transmission losses (MWs or funds) among Balancing Authority Areas.
6. Acquire Ancillary Services to support Transmission Service.
~~5.~~ 7. Update information that is relevant to a long-term Transmission Service arrangement.

Transmission Service Provider

Definition

The ~~functional~~ entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable ~~t~~Transmission ~~s~~Service agreements.[24]

Relationships with Other Functional Entities

Ahead of Time

1. Receive the methodology to determine available transfer capacity from the Transmission Operator.

~~1.~~2. Receive~~s~~ Total Transfer Capabilities, System Operating Limits and Interconnection Reliability Operating Limits from ~~Planning Coordinator,~~ the Transmission Planner~~,~~ Transmission Operator and Reliability Coordinator, and coordinates ~~A~~available ~~T~~transfer capacity~~Capability~~ with these entities and other Transmission Service Providers.

~~2. Receives transmission Facility Ratings from Transmission Owners.~~

3. Receive~~s~~ ~~t~~Transmission expansion plans identified by the~~-~~ Transmission Planner(s) ~~Planning Coordinator~~ to help determine ability to accommodate long-term ~~t~~Transmission ~~s~~Service requests.

4. Arrange for providers of Ancillary Services, and notify the Transmission Operator and Balancing Authority.

5. ~~Approves~~ Accept or ~~denies~~ decline ~~t~~Transmission ~~s~~Service requests from Purchasing-Selling Entities, Generator Owners, and Load-Serving Entities.

~~6. Confirms validity of transmission service requests indicated in the Arranged Interchange with Interchange Coordinators.~~

~~7.~~6. Develop~~s~~ ~~a~~Agreements or procedures with Transmission Owners.

7. Receive~~s~~ ~~final approval or denial of~~ Arranged Interchange from Interchange Coordinator.

8. Send approval or denial of Arranged Interchange to Interchange Coordinator based on meeting Transmission Service arrangements.

9. Receive notice of final approval or denial of Arranged Interchange becoming Confirmed Interchange from Interchange Coordinator.

10. Receives updated information from Balancing Authority, Resource Planner, Load-Serving Entity, Purchasing-Selling Entity, and market operator for long-term Transmission Service arrangement.

Real-time

~~8.~~11. Receive~~s~~ Confirmed Interchange revisions ~~implementation~~ (including ~~c~~Curtailments) from the Interchange Coordinators.

12. Receive Confirmed Interchange Interruption status from Interchange Coordinator.

~~9.~~13. Receive~~s~~ reliability alerts from Reliability Coordinator.

14. Provide~~s~~ loss allocation to Balancing Authorities.

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[24] Definition of Transmission Service Provider from the NERC Glossary of Terms (as of May 15, 2016).

15. Notify the Transmission Operator and Balancing Authority of changes to Ancillary Services.

Transmission Ownership and Transmission Owner

Transmission Ownership

Tasks

1. Develop interconnection ~~a~~Agreements.
2. Establish ~~r~~Ratings of ~~t~~Transmission facilities.~~.~~[25]
3. Maintain ~~t~~Transmission facilities and rights-of-way.
4. Design and install owned facilities classified as ~~t~~Transmission and obtain associated rights-of-way.
5. Design and authorize maintenance of ~~t~~Transmission protective relaying systems and ~~Special Protection Systems~~Remedial Action Schemes.
6. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.
7. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

[25] The Glossary definition of "Facility" is not appropriate because the definition is limited in application to BES Elements. In this context, the intent is to have broader application for non-BES elements.

Transmission Owner

Definition

The ~~functional~~ entity that owns and maintains transmission ~~f~~Facilities.[26]

Relationships with Other Functional Entities

1. Coordinate~~s~~ with Transmission Planners, ~~and~~ the Planning Coordinator, ~~Generator Owners,~~ and other Transmission Owners, ~~and Load-Serving Entities~~ desiring to connect with the Transmission system under the purview of the Transmission Owner. ~~the Bulk Electric System.~~
2. Receive~~s~~ approved ~~t~~Transmission expansion plans from the Transmission Planner.
3. Develop~~s~~ agreements or procedures with the Transmission Service Providers.
4. Develop~~s~~ operating agreements or procedures with the Transmission Operators, Reliability Coordinators and Distribution Providers.
5. Develop~~s~~ agreements with adjacent Transmission Owners for joint ~~t~~Transmission facilities.
6. Provide~~s~~ ~~t~~Transmission expansion plans and changes to the Planning Coordinator and Transmission Planners.
7. Provide~~s~~ ~~t~~Transmission Facility Ratings to Transmission Operators, Reliability Coordinators, Transmission Service Providers, Distribution Providers, Transmission Planners, and Planning Coordinator.
8. Provide~~s~~ maintenance and construction plans and schedules to the Reliability Coordinator, Transmission Operator, and Transmission Planner.
9. Coordinate and ~~D~~develop~~s~~ interconnection agreements with the Distribution Providers, ~~and~~ Generation Owners, and Load Serving Entities desiring to connect with the Transmission system under the purview of the Transmission Owner ~~for connecting to the Bulk Electric System~~.
10. Provide~~s~~ reactive resources to Transmission Operators.
11. Revise~~s~~ ~~t~~Transmission maintenance plans as requested by a Transmission Operator or the Reliability Coordinator.

[26] Definition of Transmission Owner from the NERC Glossary of Terms (as of May 15, 2016).

Distribution and Distribution Provider

Distribution

Tasks

1. Provide and operate electrical delivery ~~f~~Facilities between the ~~t~~Transmission system and the ~~E~~end-use ~~C~~customer or distribution-connected energy resource.

2. Identify and characterize its connected load and energy resources.

~~2.~~3. Implement voltage reduction.

~~3.~~4. Design and maintain protective relaying systems, under-frequency load-shedding systems, under-voltage load-shedding systems, and Remedial Action Schemes~~Special Protection Systems~~ that interface with the ~~t~~Transmission system.

~~4.~~5. Provide and implement load-shed capability.

~~5.~~6. Maintain voltage and power factor within specified limits at the interconnection point.

7. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.

8. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

Distribution Provider

Definition

The functional entity that provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage.[27] ~~The functional entity that provides facilities that interconnect an End-use Customer load and the electric system for the transfer of electrical energy to the End-use Customer.~~

Introduction to the Distribution Provider

The Distribution Provider delivers ~~e~~Electrical ~~e~~Energy ~~to the End-use Customer~~ from the ~~t~~Transmission system to the ~~E~~end-use ~~C~~customer. ~~For those End-use Customers who are served at transmission voltages, the Transmission Owner may also serve as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.~~ The Distribution Provider provides the switches and re-closers that could be used to shed load for ~~e~~Emergency action.

Relationships with Other Functional Entities

Ahead of Time

1. Coordinate~~s~~ with Transmission Planners on interconnected load and energy resources to support ~~t~~Transmission analysis~~expansion~~.
2. Coordinate~~s~~ ~~s~~System restoration plans with Transmission Operator.
3. Coordinate~~s~~ with ~~E~~end-use ~~C~~customers, distributed energy resources, and Load-Serving Entities to identify new ~~f~~Facility connection needs.
4. Develop interconnection agreements with Transmission Owners on a ~~f~~Facility basis.
5. Provide~~s~~ operational data to Transmission Operator.
6. Coordinate with Load-Serving Entities to identify critical loads that are to be precluded from load-shedding where avoidable.
7. Provide protective relaying systems, under-frequency load-shedding systems, under-voltage load-shedding systems, and Remedial Action Schemes as defined by the Transmission Planner and Planning Coordinator.

Real-time

8. Obtain voltage and power factor requirements from the Transmission Operator.

~~6.~~9. Implement~~s~~ voltage reduction and shed~~s~~ load as directed by the Transmission Operator or Balancing Authority.

~~7.~~10. Implement~~s~~ ~~s~~System restoration plans as coordinated by the Transmission Operator.

~~8.~~11. Direct~~s~~ Load-Serving Entities to communicate requests for voluntary load ~~c~~Curtailment.

[27] Definition of Distribution Provider from the NERC Glossary of Terms (as of May 15, 2016).

Generator Operation and Generator Operator

Generator Operation

Tasks

1. Formulate daily generation plan.
2. Report operating and availability status of generator Facility(ies) ~~units~~ and related equipment, such as automatic voltage regulator~~s~~ equipment, power system stabilizer equipment and frequency regulating equipment.
3. Operate generator~~s~~ Facility(ies) to provide ~~r~~Real Power and ~~r~~Reactive ~~p~~Power or Interconnected Operations Services ~~reliability-related services~~ in accordance with ~~per~~ contracts or arrangements.
4. Monitor the status of generator~~ing~~ ~~f~~Facility(ies).
5. Support Interconnection frequency and voltage.
6. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.
7. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

Generator Operator

Definition

The ~~functional~~ entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services~~reliability related services~~.[28]

Relationships with Other Functional Entities

Ahead of Time

1. Provide~~s~~ generation commitment plans to the Balancing Authority.
2. Provide~~s~~ Balancing Authority and Transmission Operators with requested amount of Interconnected Operations Services (IOS)~~reliability-related services~~.
3. Provide~~s~~ availability and operating ~~and availability~~ status of generator~~ing~~ ~~units~~ Facility(ies), to Reliability Coordinator, Balancing Authority and Transmission Operators for reliability analysis.
4. Report~~s~~ status of automatic voltage regulating equipment and power system stabilizer equipment ~~or frequency regulating equipment to~~ Transmission Operators.

~~4.~~5. Report on frequency regulating equipment to Balancing Authority.

~~5.~~6. Provide~~s~~ operational data to Reliability Coordinator, Balancing Authority and Transmission Operator.

~~6.~~7. ~~Receives reliability analyses from Reliability Coordinator.~~

~~7.~~8. Receive~~s~~ notice from Purchasing-Selling Entity if Arranged Interchange approved or denied.

~~8.~~9. Receive~~s~~ reliability alerts from Reliability Coordinator.

~~9.~~10. Receive~~s~~ notification of ~~t~~Transmission system problems from Transmission Operators.

Real-time

~~10.~~11. Provide~~s~~ Real-time operating information to the Transmission Operators and the required Balancing Authority.

~~11.~~12. Adjust~~s~~ ~~r~~Real Power and ~~r~~Reactive ~~p~~Power as directed by the Balancing Authority and Transmission Operators.

[28] Definition of Generator Operator from the NERC Glossary of Terms (as of May 15, 2016).

Generator Ownership and Generator Owner

Generator Ownership

Tasks

1. Establishes generat~~i~~or~~ng~~ ~~facilities~~ Facility ~~r~~Ratings, limits, and operating requirements.
2. Designs and authorizes maintenance of the generat~~i~~or~~n~~ ~~plant~~ protective relaying systems, protective relaying systems on the ~~t~~Transmission lines connecting the generat~~i~~or~~n~~ ~~plant~~ to the ~~t~~Transmission system, and Remedial Action Schemes (RAS)~~Special Protection Systems~~ related to the generator.
3. Performs or authorizes ~~Maintains~~ maintenance of ~~owned~~ generator~~ing~~ ~~f~~Facilities.
4. Provides verified generat~~i~~or~~ng~~ ~~f~~Facility performance characteristics / data.
5. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.
6. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

Generator Owner

Definition

The ~~functional~~ entity that owns and maintains generating Facility(ies)~~units~~.[29]

Relationships with Other Functional Entities

Ahead of Time

1. Provide~~s~~ generator Facility(ies) information to the Transmission Operator, Reliability Coordinator, Balancing Authority, Transmission Planner, and Resource Planner.
2. Provide~~s~~ generator Facility(ies) ~~unit~~ maintenance schedules and generator Facility(ies) ~~unit~~ retirement plans to the Reliability Coordinator, Transmission Operator, Balancing Authority, Transmission Planner, and Resource Planner.
3. Develop~~s~~ ~~an~~ interconnection ~~a~~Agreement(s) with Transmission Owner on a ~~f~~Facility basis.
4. Receive~~s~~ approval or denial of ~~t~~Transmission ~~s~~Service request from Transmission Service Provider.
5. Provide~~s~~ Interconnected Operations Services ~~reliability related services~~ to Purchasing-Selling Entity pursuant to agreement.

~~6. Reports the annual maintenance plan to the Reliability Coordinator, Balancing Authority and Transmission Operator.~~

6. Revise~~s~~ the generat~~ion~~or maintenance plans as requested by the Balancing Authority, Transmission Operator, and Reliability Coordinator.
7. Submit Request for Interchange to the Interchange Coordinator.
8. Submit approval for original or revised Arranged Interchange to the Interchange Coordinator.
9. ~~7.~~ Receive communication that Arranged Interchange has become Confirmed Interchange from the Interchange Coordinator.

Real-time

10. Receive Confirmed Interchange Interruptions status from the Interchange Coordinator.
11. ~~8.~~ Receive Confirmed Interchange revisions (including Curtailments) from the Interchange Coordinator.

[29] Definition of Generator Owner from the NERC Glossary of Terms (as of May 15, 2016).

Purchasinge-Selling and Purchasinge-Selling Entity

Purchasinge-Selling

Tasks

1. Purchase and sell energy or capacity.
2. Arrange for ~~t~~Transmission ~~s~~Service that is required to implement an Interchange Transaction~~by tariffs~~.
3. Request implementation of Arranged Interchange.

Purchasinge-Selling Entity

Definition

The ~~functional~~ entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services~~reliability related services~~. Purchase-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.[30]

Relationships with Other Functional Entities

Ahead of Time

1. Arrange for energy and capacity from Generator Owners.
2. Arrange~~s~~ for ~~t~~Transmission ~~s~~Service from Transmission Service Providers and makes arrangements for self-provided Interconnected Operations Services ~~reliability-related services~~ with Generator Owners or Load-Serving Entities.
3. Submit~~s~~ Requests For Interchange to Interchange Coordinators.

~~3.~~4. Submit approval for original or revised Arranged Interchange to Interchange Coordinator.

~~4. Notifies Generator Operators and Load-Serving Entities if Arranged Interchange requests are approved or denied.~~

5. Receive~~s~~ communication that ~~final approval or denial of~~ Arranged Interchange has become Confirmed Interchange from the Interchange Coordinator.
6. Receive~~s~~ ~~load~~ Demand profiles and forecasts from Load-Serving Entities.

Real-time

7. Receive notice of Confirmed Interchange Interruptions from Interchange Coordinator.
8. Receive notice of Confirmed Interchange revisions (including Curtailments) from Interchange Coordinator.

~~7.~~9. Notif~~ies~~y Interchange Coordinators of Confirmed Interchange and Implemented Interchange cancellations or terminations.

~~8.~~10. Receive~~s~~ notice of Confirmed Interchange ~~c~~Curtailments from -Interchange Coordinator.

[30] Definition of Purchasing-Selling Entity from the NERC Glossary of Terms (as of May 15, 2016).

Load-Serving and Load-Serving Entity

Load-Serving

Tasks

1. Collect individual load profiles and characteristics.
2. Identify capability for and communicate requests for voluntary load ~~c~~Curtailment.
3. Identify and communicate ~~Participate in under-frequency load shedding systems and under-voltage load shedding systems through identification of~~ critical customer loads that are to be excluded from the load-shedding systems.
4. Identify the resources needed for ~~facilities and provide capability of~~ self-provided Interconnected Operations Services (IOS) ~~reliability-related services for its load~~.
5. Develop overall load profiles and forecasts of end-user energy requirements.
6. Acquire necessary ~~t~~Transmission ~~s~~Service, and provide for Interconnected Operations Services~~reliability-related services~~.
7. Arrange for ~~Submits Requests For~~ Interchange ~~to Interchange Coordinators.~~
8. Manage resource portfolios to meet ~~demand~~ Demand and energy delivery requirements. ~~of End-use Customers.~~

Load-Serving Entity

Definition

~~The functional entity that~~ ~~secures~~ Secures energy and ~~t~~Transmission ~~s~~Service (and Interconnected Operations Services)~~reliability related services)~~ to serve the electrical demand and energy requirements of its end-~~-~~use customers.[31]

Relationships with Other Functional Entities

Ahead of Time

1. Submit~~s~~ load data ~~profiles and characteristics, plans, and forecasts~~ as needed to the appropriate entity (*e.g.*, ~~-~~Balancing Authorities, ~~Purchasing-Selling Entities, Planning Coordinator,~~ and Resource Planners, and Transmission ~~Planners~~Service Provider) in accordance with applicable tariffs, interconnection agreements or other arrangements.
2. Coordinate with Distribution Provider to identify critical loads that are to be excluded from load-shedding. ~~Identifies new facility connection needs for End-use Customers.~~
3. Provides generation commitments and dispatch schedules to the Balancing Authority.
4. Provide~~s~~ information regarding~~as to~~ self-provided Interconnected Operations Services (IOS) ~~reliability-related services~~ to the Balancing Authority.
5. Provide~~s~~ necessary data ~~planned~~ ~~purchases~~ to the Resource Planner and Transmission Planner for ~~s~~System modeling and reliability evaluation.
6. Arrange~~s~~ for ~~t~~Transmission ~~s~~Service from Transmission Service Providers and makes arrangements for Ancillary Services ~~reliability-related services~~ with Generator Owners or Load-Serving Entities.
7. Submit~~s~~ Requests For Interchange to Interchange Coordinator~~s~~.

~~7.~~8. Submit approval for original or revised Arranged Interchange to Interchange Coordinator.

9. Receive communication that Arranged Interchange has become Confirmed Interchange from the Interchange Coordinator.

~~8.~~10. Notif~~y~~~~ies~~ Generator Operators if Arranged Interchange requests are approved or denied.

~~9. Receives final approval or denial of Arranged Interchange from Interchange Coordinator.~~

~~10.~~11. Coordinate~~s~~ with Distribution Provider on identifying new ~~f~~Facility interconnection needs.

~~10. Receives notification from Purchasing-Selling Entity if Arranged Interchange requests approved or denied.~~

Real-time

~~11.~~12. Receive~~s~~ requests from the Reliability Coordinator, Balancing Authority, Transmission Operator, and Distribution Provider ~~-~~for voluntary load ~~c~~Curtailment.

~~12.~~13. Communicate requests for voluntary load ~~c~~Curtailment to end-use customers as directed by the Reliability Coordinator, Balancing Authority, Transmission Operator, and Distribution Provider.

[31] Definition of Load-Serving Entity from the NERC Glossary of Terms (as of May 15, 2016).

~~13. Notifies Interchange Coordinators of Confirmed Interchange cancellations or terminations.~~

14. Receives~~s~~ notice of Confirmed Interchange revisions (including ~~c~~Curtailments) from Interchange Coordinator.

~~14.~~15. Receive notice of Confirmed Interchange Interruptions from Interchange Coordinator.

Section IV: Version History

[This section will be completed prior to seeking final approval from the Standards Committee.]

Summary of Revisions to Reliability Functional Model

Functional Model Advisory Group

Background Information

Background regarding the Reliability Functional Model and Reliability Functional Model Technical Document

The Reliability Functional Model (FM) is a guideline that identifies the functions that must be performed to ensure that the Bulk Power System (BPS) is planned and operated in a reliable manner. The FM describes, in general terms, the functions that must be performed to ensure reliability, the specific tasks that are necessary to perform each function, and the relationships between functional entities that perform the various tasks. In its capacity of a guideline, the FM serves to provide a framework for NERC Reliability Standards as they are developed through the standard development process. The FM is independent of any particular organizational or market structure. The focus of the FM is solely on identification of reliability-related functions and the associated tasks and relationships. The FM is **not** a "standard" and does not have compliance effects. If there is a conflict between the FM and Reliability Standards, the Reliability Standards always take precedence. Also, the FM is **not** intended to identify the entities responsible for NERC registration. The NERC registration process is undertaken by NERC (and the Regional Entities) pursuant to authority from FERC, ultimately derived from the Federal Power Act. The FM has no authority, ability, or intent to impact or influence the NERC Registration process. The Reliability Functional Model Technical Document (FMTD) is a companion document to the FM. It serves to elaborate on the manner in which the various functional entities carry out their functions and perform their tasks.

Background regarding the Functional Model Advisory Group

The purpose of the Functional Model Advisory Group (FMAG), as outlined in the FMAG Scope document, is to (1) maintain the FM and FMTD to ensure the model correctly reflects the industry today, and (2) evaluate and incorporate new and emergent reliability-related tasks. The FMAG reports to the Standards Committee (SC), and works with the Planning Committee (PC), Operating Committee (OC), and Critical Infrastructure Protection Committee (CIPC) to obtain consensus regarding any proposed changes to the FM and FMTD. All proposed changes to the FM must be posted for industry comment, obtain consensus agreement from the PC, OC, and CIPC, and, ultimately, approval by the SC.

Overview of the 2016 FMAG project

In December 2015, the FMAG began a comprehensive review and assessment of the FM and FMTD to determine if it correctly reflects the industry today and whether there was a need to incorporate any new or emerging reliability-related tasks. As a result of the review, the FMAG identified many areas in need of revision. Below is a general summary of the type and nature of the revisions proposed by the FMAG.

General Overview of Proposed Revisions

1. Incorporated defined terms from the NERC Glossary of Terms: A large majority of the proposed revisions relate to incorporation of definitions from the NERC Glossary of Terms. For each proposed revision, the FMAG undertook a review to determine whether it was appropriate to incorporate the defined term, given the context and usage of the term in the FM. In some instances, the Glossary term was not used because the FMAG did not believe it had the intended meaning of the defined term, as used in the FM. In some instances, the term was simply capitalized to indicate it had the meaning of the Glossary term. In other instances, the word or phrase was replaced with a defined term (*i.e.*, reliability-related services replaced with Interconnected Operations Service).

2. Consolidated ERO-related functions: In the current version of the FM (version 5), there are separate functions for Standards Developer, Compliance Enforcement Authority and Reliability Assurance. The FMAG believes that all of these fall under one "function" of ensuring the reliability of the BPS. Therefore, all functions related to reliability assurance were moved to the Reliability Assurance function. The Reliability Assurance function is intended to include any tasks performed by the Electric Reliability Organization (ERO) to ensure the reliability of the BPS, including, for example, development of Reliability Standards, development and implementation of a compliance and enforcement program, and development and maintenance of a program for identifying and registering entities responsible for compliance.

3. Clarified the planning functions: Planning Coordinator (PC), Transmission Planner (TP), and Resource Planner (RP): The proposed revisions seek to identify the differences in the various planning functions, the tasks performed by the functional entities, and how the planners work together to ensure the Bulk Electric System (BES) has adequate reliability planning.

4. Clarified how Interchange occurs: The proposed revisions provide clarity regarding how the various functions and functional entities work together to perform Interchange, including incorporation of appropriate Glossary terms (*i.e.*, Requests for Interchange, Arranged Interchange, Confirmed Interchange).

5. Added cyber and physical security tasks: The FMAG is proposing to add two new tasks related to security protections for cyber assets and physical assets, and communication regarding an actual or suspected threat to those assets. The new tasks have been added to the following functions:

- Reliability Coordinator (RC)
- Balancing Authority (BA)
- Transmission Operator (TOP)
- Transmission Owner (TO)
- Interchange Coordinator (IC)
- Distribution Provider (DP)
- Generator Owner (GO)
- Generator Operator (GOP).

45-day informal comment period

The proposed revisions to the FM and FMTD are posted for a 45-day informal comment period. The FMAG will review all comments submitted and incorporate, as appropriate, proposed revisions to the FM and FMTD. In the documents posted for comment, the highlighted language is intended to indicate that the revision relates to a substantive change. The FMAG requests that you focus your comments on these highlighted revisions. Revisions that are not deemed substantive include revisions related to:

- Incorporation of a Glossary term;
- Clarification to the existing language (*i.e.*, use of consistent terminology);
- Changes to the order or manner of presentation of information (*i.e.*, rearrangement of tasks to follow a chronological order of how the tasks are performed);
- Consolidation of related items or removal of redundancies; and
- Changes to reflect how Interchange works, including incorporation of NERC Glossary terms.

Below is a mapping of the proposed revisions, along with an explanation of why the revision was needed necessary.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
1	General (Executive Summary, Introduction, Purpose, etc.)	Consolidated general background information and into one section (Section I – Purpose of the FM).	Provided clear, concise summary of the purpose of the FM; also, explained that the FM is a guideline and not a standard, nor does it identify entities for NERC Registration.
2	Standards Developer	Deleted entire section	See “Reliability Assurer” section

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
3	Compliance Enforcement Authority	Deleted entire section	See “Reliability Assurer” section
4	Reliability Assurer	Revised section to include greater detail regarding the tasks performed by the ERO (and the Regional Entities).	Identified the various tasks performed by NERC (and the Regional Entities) in its role as the ERO.
5	Planning Coordinator	Revised entire section to provide clarity regarding the differences in roles and tasks performed by the planning entities (*i.e.*, Planning Authority, TP, and RP). Also, provided greater clarity regarding how the planners work together to ensure the BES has adequate reliability planning.	New Tasks 1, 2, 3 work together to outline the sequential process followed by the PC to conduct transmission system assessments. The component of “analysis and development of resource adequacy plans” was intentionally removed from the PC tasks. With regard to the assessments performed: • Both the TP and PC perform assessments to evaluate whether future transmission system performance will meet the minimum acceptable system performance requirements. However, the TP and PC may consider different system conditions (and BES facilities) in performing their respective assessments; this flexibility allows for studying a wider range of system conditions and allows for a more complete and comprehensive assessment of the BES. • TP assessment includes the collection of transmission assets over which the TP is responsible for planning (“TP Area”). • PC assessment includes the collection of transmission assets over which the PC is responsible for coordinating planning (“PC Area”). The PC Area is normally comprised of more than one TP. The PC focuses on assessments of both Transmission and resource planning for its PC Area. • Every BES facility must have one associated TP and at least one PC. This means that every facility in the TP Area

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
			should be included in the assessment conducted by the TP.
6	Transmission Planner	Deleted Task No. 7: ~~Define system protection and control needs and requirements, including special protection systems (remedial action schemes), to meet reliability needs.~~	The nature of the TP's work requires that the TP has an understanding of the "typical" system protection and control schemes utilized by the associated Transmission Owner(s). Through interaction with the TO, the TP can also have an influence on the system protection scheme standards that a TO uses. In some instances, the TP may recommend a Remedial Action Scheme (RAS) as a means of addressing Transmission system performance issues. The TP's awareness of, and influence on, system protection schemes were viewed as an integral part of the TPs' modeling and assessment tasks. The FMAG determined that a discussion of the TP's involvement with protection systems was better suited to the FMTD. Therefore the task was deleted.
7	Transmission Planner	Revised Relationship No. 9: Deleted "Resource Planner" and added "Planning Coordinator" "Submits and coordinates the plans for the interconnection of facilities to the Bulk Electric System within its Transmission Planner area with other Transmission Planners and the Planning Coordinator~~Resource Planners~~, as appropriate."	Removed "Resource Planner" and added "Planning Coordinator" because the PC is also concerned with transmission system assessments, whereas the RP is not.
8	Transmission Planner	Revised Relationship No. 10: Added "Planning Coordinator"	Added "Planning Coordinator" because of the PCs role and interest in assessing transfer capability.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
		"Coordinates and develops transfer capability values with other Transmission Planners, Reliability Coordinators, Transmission Operators, Transmission Owners ~~and~~ Transmission Service Providers, and the Planning Coordinator."	
9	Resource Planner	Revised entire section to provide clarity and to distinguish resource planning tasks from other planning functions. Also, provided greater clarity regarding how the RPs interact with the TPs and Transmission Service Providers to ensure the BES has adequate resource planning.	Removed the prescriptive language to emphasize the completion of the task versus "how to perform" the task. Also, revised the language to improve clarity of the functional relationships.
10	Reliability Coordinator	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 11: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 12: "Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets."	New Task No. 11: Additional task necessary to identify RC reliability related responsibilities associated with cyber and physical security. New Task No. 12: Additional task necessary to identify RC communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.
11	Reliability Coordinator	Revised Relationship No. 2: Added Distribution Providers	Added DP because the RC receives reliability-related facility and operational data from the DP.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
		"Receives facility and operational data from Generator Operators, Distribution Providers, Load-Serving Entities, Transmission Owners, Generator Owners, and Transmission Operators."	
12	Reliability Coordinator	Revised Relationship No. 6: "Develop~~s~~ Interconnection Reliability Operating Limits, and provide them to those entities with a reliability-related need~~based on Transmission Owners' and Generator Owners' specified equipment ratings, and provides them to Transmission Operators~~."	Revised the relationship to reflect fact that RC establishes IROLs based on a number of factors (not limited to the equipment ratings); and the RC communicates the IROLs to various entities (not solely the TOP) based upon the specific requirements outlined in the RC's methodology or specific procedure in place.
13	Reliability Coordinator	Deleted Relationship No. 12: Duplicative ~~"Provide IROLs and TTC to the Transmission Service Provider for ATC calculation."~~	This is covered in Relationship No. 6.
14	Balancing Authority	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 14: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 15: "Communicate to appropriate authorities and relevant functional	New Task No. 14: Additional task necessary to identify BA reliability related responsibilities associated with cyber and physical security. New Task No. 15: Additional task necessary to identify BA communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
		entities of an actual or suspected attack on cyber assets and/or physical assets.”	
15	Balancing Authority	Added new Relationship: New Relationship No. 1: “Ahead of Time: Receive generator Facility plans from Generator Operators within the Balancing Authority Area.”	Clarifies how and when information is provided from GOP in the BA Area.
16	Balancing Authority	Added new Relationship: New Relationship No. 2: “Ahead of Time: Receive operational data from Generator Operators within the Balancing Authority Area.”	Clarifies how and when information is provided from the GO in the BA Area.
17	Balancing Authority	Deleted Relationship No. 2: Duplicative ~~“Receive operating and availability status of generating units from Generator Operators within the Balancing Authority Area.”~~	Covered in Relationship No. 14
18	Balancing Authority	Revised Relationship No. 10: Removed GOP. “Implements generator commitment and dispatch schedules from the Load-Serving Entities ~~and Generator Operators~~ who have arranged for generation within the Balancing Authority Area.”	Removed GOP because the information is from the LSE, not the GOP. The GOP operates the generator, the LSE has the schedule.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
19	Balancing Authority	Added new Relationship: New Relationship No. 1: "Receive reports on frequency regulating equipment from Generator Operators within the Balancing Authority Area."	Clarifies how and when information is provided associated with frequency regulation from the GOP in the BA Area.
20	Transmission Operator	Revised Task No. 8: "Adjust Real Power, Reactive Power and voltage ~~flow control devices within the transmission area~~ to maintain reliability."	Revised language to improve clarity regarding the task performed, while not limiting or specifying "how" the TOP maintains parameters to ensure reliability.
21	Transmission Operator	Deleted Task No. 9: Duplicative. ~~"Deploy reactive resources to maintain transmission voltage within defined limits."~~	Repeat of Task No. 8.
22	Transmission Operator	Added new Task: New Task No. 9: "Determine the Transmission capability that supports the Reliable Operation of the Transmission Operator Area."	Additional task supports the required Transmission capability assessments required to be completed by the TOP.
23	Transmission Operator	Added new Task: New Task No. 10: "Operate or direct the operation of Transmission Facilities in its TOP Area."	Additional task necessary to correctly identify the TOP responsibilities associated with the operation of the Transmission System.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
24	Transmission Operator	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 14: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 15: "Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets."	New Task No. 14: Additional task necessary to identify TOP reliability related responsibilities associated with cyber and physical security. New Task No. 15: Additional task necessary to identify TOP communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.
25	Transmission Operator	Revised Relationship No. 11: "Ahead of time: Provide~~s~~ Total Transfer Capabilities, ~~and~~ System Operating Limits, and methodology for calculating ~~to, and coordinates~~ Available Transfer Capability for respective Transmission paths to ~~with,~~ Transmission Service Provider."	Revised language to improve clarity of the functional relationship.
26	Transmission Operator	Revised Relationship No. 12: "Ahead of time: Receives operating and availability status of generating units from Generator~~ion~~ Operators including status of automatic voltage regulators and power system stabilizers."	Added "and power system stabilizers" to identify the need of the TOP to be aware of component status.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
27	Transmission Operator	Added new Relationship: New Relationship No.13: "Ahead of time: Receive operational data from Generator Operators."	Additional relationship necessary to ensure that the TOP has all necessary operational data to support Operations Planning functions and real-time contingency analysis.
28	Transmission Operator	Revised Relationship No. 18: "Real-time: Deploy~~s~~ reactive resources from Transmission Owners,~~ and~~ Generator Owners, and Distribution Providers to maintain acceptable voltage profiles."	Relationship expanded to include the DP as an operating authority for reactive resources.
29	Transmission Operator	Added new Relationship: New Relationship No.24: "Real-time: Receive Real-time operating information from Generator Operators."	Additional relationship necessary to ensure that the TOP has all necessary operational data to support real-time contingency analysis.
30	Interchange Coordinator	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 9: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 10: "Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets."	New Task No. 9: Additional task necessary to identify IC reliability related responsibilities associated with cyber and physical security. New Task No. 10: Additional task necessary to identify IC communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
31	Interchange Coordinator	Added new Relationship: New Relationship No. 7: “Receive reliability alerts from the Reliability Coordinators.”	This was a missing reciprocal relationship to an existing RC relationship.
32	Transmission Service Provider	Revised Task No. 2: “Determine and post available transfer ~~capability~~ capacity values.”	Changed capability to capacity to avoid Glossary conflict.
33	Transmission Service Provider	Added new Task: New Task No. 5: “Acquire Ancillary Services to support Transmission Service.”	Added task to recognize provider of last resort responsibilities for required Ancillary Services to support Transmission Services in the Open Access Transmission Tariff.
34	Transmission Service Provider	Added new Task: New Task No. 6: “Update information that is relevant to a long-term Transmission Service arrangement.”	Added task to support an existing reciprocal relationship with TP.
35	Transmission Service Provider	Added new Relationship: New Relationship No. 1: “Ahead of Time: Receive the methodology to determine available transfer capacity from the Transmission Operator.”	Added relationship to recognize TOP responsibility to develop methodology.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
36	Transmission Service Provider	Revised Relationship No. 1: "Ahead of Time: Receives~~s~~ Total Transfer Capabilities, System Operating Limits and Interconnection Reliability Operating Limits from ~~Planning Coordinator,~~ the Transmission Planner, Transmission Operator and Reliability Coordinator, and coordinates ~~A~~available ~~T~~transfer capacity ~~Capability~~ with these entities and other Transmission Service Providers."	Deleted PC. Changed ATC to available transfer capacity to avoid Glossary conflict.
37	Transmission Service Provider	Revised Relationship No. 3: "Ahead of Time: Receive~~s~~ ~~t~~Transmission expansion plans identified by the Transmission Planner(s)~~Planning Coordinator~~ to help determine ability to accommodate long-term transmission service requests."	Changed PC to TP.
38	Transmission Service Provider	Added new Relationship: New Relationship No. 4: "Ahead of Time: Arrange for providers of Ancillary Services, and notify the Transmission Operator and Balancing Authority."	Supports newly added task to provider of last resort responsibilities for required Ancillary Services to support Transmission Services in the Open Access Transmission Tariff.
39	Transmission Service Provider	Added new Relationship:	Supports newly added task to provider of last resort responsibilities for required Ancillary Services to support Transmission Services in the Open Access Transmission Tariff.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
		New Relationship No. 15: “Notify the Transmission Operator and Balancing Authority of changes to Ancillary Services.”	
40	Transmission Owner	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 6: “Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.” New Task No. 7: “Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.”	New Task No. 6: Additional task necessary to identify TO reliability related responsibilities associated with cyber and physical security. New Task No. 7: Additional task necessary to identify TO communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.
41	Transmission Owner	Revised Relationship No. 1: “Coordinates with Transmission Planners and the Planning Coordinator, Generator Owners, other Transmission Owners, and Load-Serving Entities desiring to connect with the Bulk Electric System.”	Deleted GO and LSE. Clarified scope.
42	Transmission Owner	Revised Relationship No. 9: “Develops interconnection agreements with the Distribution Providers and Generation Owners for connecting to the Bulk Electric System.”	Deleted LSE.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
43	Distribution Provider	Revised Task No. 1: "Provide and operate electrical delivery ~~f~~Facilities between the ~~t~~Transmission system and the ~~E~~end-~~u~~Use ~~C~~customer or distribution-connected energy resource."	Added "distribution-connected energy resource" to recognize increasing number of these types of resources that impact the amount of energy supplied to the BES.
44	Distribution Provider	Added New Task: New Task No. 2: "Identify and characterize its connected load and energy resources."	DP should understand the characteristics of the load and resources connected to its system, which can have an impact on the BES performance.
45	Distribution Provider	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 7: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 8: "Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets."	New Task No. 7: Additional task necessary to identify DP reliability-related responsibilities associated with cyber and physical security. New Task No. 8: Additional task necessary to identify DP communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.
46	Distribution Provider	Revised Relationship No. 1: "Ahead of time: Coordinate~~s~~ with Transmission Planners on interconnected load and energy	Added energy resources instead of only load.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
		resources to support ~~t~~Transmission analysis~~expansion~~."	
47	Distribution Provider	Revised Relationship No. 3: "Ahead of time: Coordinate~~s~~ with ~~E~~end-use ~~C~~customers, distributed energy resources, and Load-Serving Entities to identify new ~~f~~Facility connection needs."	Added "distribution-connected energy resource" to recognize increasing number of these types of resources that impact the amount of energy supplied to the BES.
48	Distribution Provider	New Relationship added: New Relationship No. 7: "Ahead of time: Provide protective relaying systems, under-frequency Load shedding systems, under-voltage Load shedding systems, and Remedial Action Schemes as defined by the Transmission Planner and Planning Coordinator."	Relationship added to support existing Task No. 4
49	Distribution Provider	New Relationship added: New Relationship No. 8: "Real-time: Obtain voltage and power factor requirements from the Transmission Operator."	Relationship added to support existing Task No. 6
50	Generator Operator	Revised Task No. 5: "Support Interconnection frequency and voltage."	Accounted for GOP task of contributing to voltage support.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
51	Generator Operator	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 6: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 7: "Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets."	New Task No. 6: Additional task necessary to identify GOP reliability related responsibilities associated with cyber and physical security. New Task No. 7: Additional task necessary to identify GOP communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.
52	Generator Operator	Revised Relationship No. 3: "Ahead of Time: Provide~~s~~ availability and operating ~~and availability~~ status of generator~~ing~~ Facilities~~units~~ to Reliability Coordinator, Balancing Authority and Transmission Operators for reliability analysis."	Added RC.
53	Generator Operator	Revised Relationship No. 4: "Ahead of Time: Report~~s~~ status of automatic voltage regulating equipment and power system stabilizer equipment ~~or frequency regulating equipment~~ to Transmission Operators."	Deleted frequency regulating equipment; added as a new task.
54	Generator Operator	Added new Relationship:	Added new Relationship to support existing Task.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
		New Relationship No. 5: "Ahead of Time: Report on frequency regulating equipment to Balancing Authority."	
55	Generator Operator	Revised Relationship No. 5: "Ahead of Time: Provides operational data to Reliability Coordinator, Balancing Authority and Transmission Operator."	Added BA and TOP.
56	Generator Owner	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 5: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 6: "Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets."	New Task No. 5: Additional task necessary to identify GO reliability related responsibilities associated with cyber and physical security. New Task No. 6: Additional task necessary to identify GO communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.
57	Generator Owner	Revised Relationship No. 2: "Provide~~s~~ Facility~~unit~~ maintenance schedules and ~~unit~~ generator Facility retirement plans to the Reliability Coordinator, Transmission Operator, Balancing Authority, Transmission Planner, and Resource Planner."	Added RC.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
58	Generator Owner	Revised Relationship No. 7: "Revises the generator~~ion~~ maintenance plans as requested by the Balancing Authority, Transmission Operator, and Reliability Coordinator."	Added BA and TOP.
59	Purchasing-Selling Entity	Added New Relationship No. 1: Arrange for energy and capacity from Generator Owners.	Added missing reciprocal relationship for Task No. 1.
60	Load-Serving Entity	Revised Task No. 3: "Identify and communicate ~~Participate in under-frequency load shedding systems and under-voltage load shedding systems through identification of~~ critical customer loads that are to be excluded from the load shedding systems."	Added communication element.
61	Load-Serving Entity	Revised Relationship No. 1: "Ahead of Time: Submit~~s~~ load data~~profiles and characteristics, plans, and forecasts~~ as needed to the appropriate entity (*e.g.*, Balancing Authorities, ~~Purchasing-Selling Entities, Planning Coordinator,~~ Resource Planners, and Transmission Service Providers~~Planners~~) in	Link the load data submission need and types to applicable tariff, interconnection agreements or other arrangements as opposed to a generic set.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
		accordance with applicable tariffs, interconnection agreements or other arrangements."	
62	Load-Serving Entity	Revised Relationship No. 2: "Ahead of Time: Coordinate with Distribution Provider to identify critical loads that are to be excluded from load-shedding~~Identifies new facility connection needs for End-use Customers~~."	Clarify that the DP is the entity impacted by the identified information.
63	Load-Serving Entity	Revised Relationship No. 12: "Real-time: Receive~~s~~ requests from the Reliability Coordinator, Balancing Authority, Transmission Operator, and Distribution Provider for voluntary load ~~c~~Curtailment."	Added RC and TOP, who also make these requests.
64	Load-Serving Entity	Revised Relationship No. 13: "Real-time: Communicate requests for voluntary load ~~c~~Curtailment to end-use customers as directed by the Reliability Coordinator, Balancing Authority, Transmission Operator and Distribution Provider."	Added RC and TOP, who also make these requests.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reliability Functional Model Technical Document

Version 6~~5~~

Prepared by the Functional Model Advisory Group
Approved by the Standards Committee: [Month, Year]

RELIABILITY | ACCOUNTABILITY

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Table of Contents

Introduction

The Functional Model Technical Document (FMTD) ~~This document~~ is intended as a companion to Version ~~5~~ 6 of the Functional Model to help explain the functions, including the functional entities, the respective tasks performed by each functional entity, and the relationships with other functional entities that are necessary to perform the tasks. ~~the reader better understand the Model's Functions, functional entities and their relationships. This document therefore provides context, explanation and opinions. It is a companion to, rather than a formal part of, Version 5 of the Model.~~

Section I – Functional Entity Tasks and Interrelationships provides details regarding the functional entity tasks and interrelationships. ~~about each of the Responsible Entities.~~ A number of the ~~Some~~ functional entities, such as the Transmission Owner or Purchasing-Selling Entity, are adequately described in the FM~~unctional Model document~~, so~~and~~ there is no need to provide further ~~little~~ detail in the FMTD~~to add here~~. Other entities, such as the Interchange Coordinator and Balancing Authority, are more complex, including their ~~both unto themselves and in their~~ relationships with other functional entities, and the FMTD ~~is document~~ provides further explanation regarding how these entities work together to ensure reliability~~additional explanations~~.

Section II – Technical Discussion includes technical discussions on related topics such as managing Arranged and Confirmed Interchange, and functional entity areas and boundaries~~y conditions~~. ~~The discussion of Market Operations illustrates that the Model applies to different market structures.~~

SECTION I – FUNCTIONAL ENTITY TASKS AND INTERRELATIONSHIPS

~~Version 4 of the Model, issued in 2008, clarified the concept of responsibility in the Model, as reflected in the use of the term Responsible Entity. In particular, it was clarified that while there were responsibilities of the entities in the Functional Model within the context of the Model itself, the responsibilities that will actually apply to an organization will be determined within NERC's registration, certification and compliance processes and Reliability Standards, not by the Model.~~

~~However, it subsequently became apparent to the Functional Model Working Group that having two different contexts for responsibility did not completely eliminate the potential for confusion. On this basis, Version 5 goes one step further and eliminates reference to responsibility within the Model, replacing the term responsible entity with the term functional entity. In Version 5 of the Model, an entity is defined by the functions it performs.[1]~~

~~As a result of refocusing the Model on Tasks rather than responsibility, Version 5 of the Technical Document has removed discussions associated with responsibility of individual organizations. These matters are now addressed within the context of NERC's registration and compliance programs, typically within the NERC Rules of Procedure. These include situations where:~~

- ~~an organizations may "bundle" a number of different functions and register as the corresponding functional entities, for example Reliability Coordinator and Transmission Operator~~
- ~~two or more organizations may register jointly with NERC as functional entities and thereby divide or share responsibility for meeting standards requirements (Joint Registry Organizations)~~
- ~~an organization may register and assume responsibility for Tasks performed by others, such as a rural cooperative on behalf of its members.~~

~~[1] Version 5 of the Model uses the term "functional entity" to apply to the *entity described in the Functional Model* (Balancing Authority, etc). It is proposed that other NERC documents follow this usage, and also that they use the terms "registered entity", "certified entity" and "responsible entity", in reference to *specific organizations*. For example, PJM is a registered entity and certified entity for the Balancing Authority functional entity.~~

Part 1 - Reliability Coordinator

The Reliability Coordinator~~'s~~ purview must be broad enough to enable it to ~~calculate~~ establish Interconnection Reliability Operating Limits, which will involve ~~s~~System and facility operating parameters beyond its own Area as well as within it. This is in contrast to the Transmission Operator, which also maintains reliability, but is directly concerned with system parameters within its own Area.

The Reliability Coordinator is the highest operating authority; the underlying premise is that reliability of a wide-area takes precedence over reliability of any single local area. Only the Reliability Coordinator has the perspective/vision necessary to act in the interest of wide-area reliability.

The Reliability Coordinator also assists the Transmission Operator in monitoring for and relieving equipment or facility overloads through transmission loading relief measures if market-based dispatch procedures are not effective.

Role in Interchange. The Reliability Coordinator does not receive tags, but may curtail Interchange Transactions until they are arranged and ready for implementation as Interchange Schedules. As such, it does not approve or deny tags. However, once the Reliability Coordinator receives the Interchange Schedule information, it will have the necessary information to aid its assessment of the impacts of flowing and impending Transaction Schedules on its area's reliability. As necessary, the Reliability Coordinator may issue transmission loading relief requests (or similar requests for congestion management) which may result in reducing, removing or halting flowing or impending Interchange Transactions. This is viewed by some as "denying" the Interchange Transactions although in this context, the "denial" is not provided during the collection of approval stage.

Day-ahead analysis. The Reliability Coordinator will receive the dispatch plans from the Balancing Authority(ies) on a day-ahead basis. The Reliability Coordinator will then analyze the dispatch from a transmission reliability perspective. If the Reliability Coordinator determines that the Balancing Authority's dispatch plans will jeopardize transmission reliability, the Reliability Coordinator will work with the Balancing Authority to determine where the dispatch plans need to be adjusted. The Reliability Coordinator obtains generation and transmission maintenance schedules from Generator Operators and Transmission Operators. The Reliability Coordinator has final authority in coordination and resolution of conflicts regarding transmission and generation outage requests. The Reliability Coordinator can deny a transmission outage request and some elective, generation outage requests if a transmission system reliability constraint would be violated.

The Transmission Operator is responsible for the reliability of its "local" transmission system in accordance with establishing and maintaining System Operating Limits (SOLs).However, in some circumstances, as noted above for reliability analysis associated with generation dispatch instructions, the Reliability Coordinator may become aware of a potential SOL ~~violation~~ exceedance and issue a dispatch adjustment. Therefore, in this context, the Reliability Coordinator also has a role regarding the Transmission Operator's management of SOL exceedances.

Emergency actions. The Reliability Coordinator is responsible for Real-time system reliability, which includes calling for the following emergency actions:

- Curtailing Interchange Schedules
- Directing re-dispatch to alleviate congestion or other SOL exceedances

- Mitigating energy and transmission emergencies
- Ensuring energy balance and Interconnection frequency
- Directing load shedding.

The Reliability Coordinator, in collaboration with the Balancing Authority and Transmission Operator, can invoke public appeals, voltage reductions, ~~d~~Demand-~~s~~Side ~~m~~Management, Energy Emergency alerts, and even load shedding if the Balancing Authority cannot achieve resource-demand balance.

System restoration actions. The Reliability Coordinator directs and coordinates ~~system~~ restoration of the BES for its RC Area, with Transmission Operators, ~~and~~ Balancing Authorities and other Reliability Coordinators.

~~**Authority to perform its reliability functions**. The Reliability Coordinator's authority is documented in one or more regional reliability plans, as applicable, for the Region in which the Reliability Coordinator Area is located. In cases where a Reliability Coordinator Area spreads over multiple Regions, its authority will be documented in and accepted by all the concerned Regions through their respective reliability plans.~~

In addition, since the Reliability Coordinator may also have a role regarding the Transmission Operator's management of SOL exceedances, delineation of its authority and that of the Transmission Operator needs to be clearly defined ~~in the reliability plan(s)~~.

Part 2 - Balancing Authority

The Balancing Authority operates within the metered boundaries that establish the Balancing Authority Area. Every generator, ~~t~~Transmission ~~f~~Facility, and end-use customer is in a Balancing Authority Area. The Balancing Authority's mission is to maintain the balance between ~~loads~~ Demand and resources in real time within its Balancing Authority Area by keeping its actual ~~i~~Interchange equal to its scheduled ~~i~~Interchange and meeting its ~~f~~Frequency ~~b~~Bias obligation. The demand~~load~~-resource balance is measured by the Balancing Authority's Area Control Error (ACE). In performing its balancing function, the Balancing Authority does not own the resources.

~~NERC's Reliability Standards require that t~~The Balancing Authority maintains its ACE within acceptable limits. Maintaining ~~resource-d~~Demand-resource balance within the Balancing Authority Area requires four types of resource management, all of which are the Balancing Authority's responsibility. Each of these resource management functions require sufficient resources provided to it by other entities:

- ~~F~~frequency control through tie-line bias
- Regulation ~~s~~Service deployment
- ~~L~~load-following through economic dispatch
- Interchange implementation

Frequency control through ~~t~~Tie-~~l~~Line ~~b~~Bias. To maintain frequency within acceptable limits, the Balancing Authority controls resources within its Balancing Authority Area to meet its ~~f~~Frequency ~~b~~Bias obligation to the ~~i~~Interconnection.

Regulation service deployment. To maintain its ACE within these acceptable limits, the Balancing Authority controls a set of generators within its Balancing Authority Area that are capable of providing ~~r~~Regulation ~~s~~Service.

Load-following through economic dispatch. The organization that serves as the Balancing Authority will in general also perform unit commitment and economic dispatch; however, in some markets, Generator Operators may be permitted to perform unit commitment and economic dispatch among the fleet of generators under their control and within the requirements accepted by the market operator.

Interchange implementation. The Balancing Authority receives Confirmed Interchange from one or more Interchange Coordinators, and enters those Interchange Schedules into its energy management system.

Unit commitment and schedules from Load-Serving Entities. The Balancing Authority receives resource dispatch plans from the Market Operator and/or unit commitment and dispatch ~~s~~Schedules from the Load-Serving Entities that have bilateral arrangements for generation within the market or the Balancing Authority Area. The Balancing Authority provides this commitment and dispatch ~~s~~Schedule to the Reliability Coordinator.

Role in approving Interchange. The Balancing Authority approves an Arranged Interchange with respect to the ramping requirements of the generation that must increase or decrease to implement the Interchange. The Balancing Authority provides its approval or denial to the Interchange Coordinator.

Energy Emergencies. In the event of an Energy Emergency, the Balancing Authority can implement public appeals, ~~d~~Demand-~~s~~Side ~~m~~Management programs, and, ultimately load shedding. Obviously, it must do this in concert with the Reliability Coordinator.

Failure to balance. The Balancing Authority must take action, either under its own initiative or direction by the Reliability Coordinator, if the Balancing Authority cannot comply with NERC's Reliability Standards regarding frequency control and Area Control Error.

~~See "Managing Bilateral Interchange Transactions"~~

Reserve Sharing Groups: In the past, only reserve sharing groups have been associated with Contingency Reserve. However, as the industry has evolved, additional commercial relationships between Balancing Authorities are occurring and thus creating new responsible groups. These responsible groups now include Regulation Reserve Sharing Groups, Frequency Response Sharing Groups, Frequency Response Sharing Groups and Contingency Reserve Sharing Groups. These groups are the responsible entities, but the Balancing Authorities remain responsible for performance within each respective group. The Balancing Authorities enter into commercial arrangements among themselves to form the respective sharing groups.

Part 3 - Planning Coordinator

The Planning Coordinator coordinates and integrates ~~t~~Transmission facility and service plans, resource plans, and protection system plans among the Transmission Planner(s) ~~and Resource Planner(s)~~ within its area of purview. These activities range from review and ~~integration~~ assessing~~of~~ expansion ~~reinforcement~~ and corrective action plans developed by the Transmission Planner(s) ~~functional entities whose area of responsibility is~~ within the Planning Coordinator's area ~~with respect to established reliability needs to providing procedures, protocols, modeling and methodology software, etc. for consistent use within its area~~. The assessment should consider the interaction of system changes under a range of selected scenarios across the entire Planning Coordinator area. The PC assessment includes the collection of Transmission assets over which the Planning Coordinator is responsible for coordinating planning ("PC Area"). The PC Area is normally comprised of more than one Transmission Planner; however, the area under the purview of a Planning Coordinator may include as few as one Transmission Planner. The Planning Coordinator's scope of activities is intended to span a broader area that may include BES assets of multiple Transmission Planners. All BES Facilities should be assigned to a Transmission Planner and to a Planning Coordinator, so that there are no gaps in the assessment of the BES.

Planning Coordinators work through a variety of processes to conduct facilitated, coordinated, joint, centralized, or regional planning activities to the extent that all portions of the interconnected BES are completely coordinated for planning activities. While much of what the Planning Coordinator performs could be actually performed by a Transmission Planner, such as developing methodologies in conjunction with surrounding Transmission Planners, recognition of resource plans, assessing system performance consistent with reliability needs by itself, and collaborating with other Transmission Planners to assess impacts on the interconnected area, the Planning Coordinator by its very nature will generally take responsibility over a wider perspective than the Transmission Planners for which its coordinates. The Planning Coordinator generally conducts system performance assessments, in collaboration with other Planning Coordinators to consider transfer/flows across multiple Transmission Planner areas or intra- and inter- state areas such as generation dispatch scenarios caused by temperature or fuel extremes. Geographic size is not necessarily a critical consideration, it is the extent and impact of the electrical network that the planners have taken responsibility for assessing that determines whether an area is large enough for analysis and planning

~~Although the Functional Model sets forth the concept of the Planning Coordinator and how a functional entity could perform as such, there may be situations or circumstances under actual organizational structures whereby a single entity does not exist that performs the Reliability Planning Function but rather the function is taken on by a number of entities, *e.g.*, a group of Transmission Planners, or an organization such as a regional group formed within a region or possibly the Regional Entity itself. In all these cases the Reliability Planning Function is still performed in some manner by some entity or organization.~~

The boundaries for the Planning Coordinator area are basically defined by the location of the Bulk Electric System facilities under the purview of the Planning Coordinator, *i.e.* those facilities for which the Planning Coordinator coordinates and evaluates and recommends reinforcement and corrective plans resulting from studies and analysis of system performance and interconnection of facilities. The BES facilities under its purview, are generally contiguous and cover in aggregate the same areas as the Transmission Planners its coordinates. Traditionally transmission planning has been associated with one or more Transmission Owners, *i.e.* reinforcement and corrective action plans must be associated with certain Transmission Owner facilities. Since transmission ownership may cross state or provincial or regional boundaries, the BES ~~f~~Facilities on one side of the Transmission Owner boundary may be in one Planning Coordinator area whereas the remaining facilities may be in another. As such the Planning Coordinator area is not constrained to fit within a Reliability Coordinator or Transmission Operator Area. However, the Planning Coordinator area must cover at least one Transmission Planner Area. ~~and one Resource Planner area, or part thereof if either or both of these planner areas is larger than the Planning Coordinator area. On the other hand, there is the possibility that a Planning Coordinator area could be nested inside an even larger Planning Coordinator area provided the smaller Planning Coordinator does in fact perform the appropriate system assessments. In this special case, the larger Planning Coordinator would perform the ultimate planning coordinating function for all the Resource Planners, Transmission Planner and smaller Planning Coordinator in its Area. As an example, some ISOs and RTOs perform the Reliability Planning Functions but they are also under the purview of the Regional Entity that also performs the Reliability Planning Functions at a broader scale.~~

In many areas, there may exist more than one Transmission Planner ~~and Resource Planner, as well as a nested Planning Coordinator, within a Planning Coordinator area,~~ each performing a different role demarcated primarily by their particular function and scale (area-wise) of assessments performed. In order to ensure all BES Facilities are associated with a Planning Coordinator, clear delineation of the "PC Area" should establish the BES Facilities and associated connections to its adjacent Planning Coordinators. ~~In these cases, delineation of the role of the various functional entities needs to be clearly defined in the regional reliability plan(s).~~

The Planning Coordinator is not responsible for implementing the ~~t~~Transmission and resource plans. However, it helps to facilitate the process whereby adequate resources and ~~t~~Transmission ~~f~~Facilities are placed into service in a timely and efficient manner through coordinated planning with the ~~Resource Planners,~~ Transmission Planners~~, and possibly others through the coordinated planning process~~.

Part 4 - Transmission Planner

The Transmission Planner 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.[2] ~~area of purview.~~

The Transmission Planning function is typically associated with the Transmission Ownership function. The Transmission Planner performs the tasks of modeling, simulating and assessing the performance of the Transmission system under a range of future scenarios on a recurring basis. As Transmission system performance deficiencies are identified through this process, the Transmission Planner studies alternative solutions for correcting the deficiencies. Through interactions with various stakeholders, the Transmission Planner ultimately arrives at a recommended Corrective Action Plan that will resolve the identified deficiencies. For solutions that involve Transmission system capacity expansion, the associated Transmission Owner(s) is responsible for implementing the solution.

Both the Transmission Planner and Planning Coordinator perform assessments to evaluate whether future Transmission system performance will meet the minimum acceptable system performance requirements. The Transmission Planner and Planning Coordinator may consider different system conditions (and BES Facilities) in performing their assessments. This flexibility allows the Transmission Planner and Planning Coordinator to study a wider range of system conditions, which leads to a more complete and comprehensive assessment of the BES. For example, a Transmission Planner may set higher System performance criteria for a particular area under assessment.

The Transmission Planner assessment includes the collection of Transmission assets over which the Transmission Planner is responsible for planning (“TP Area”). The Planning Coordinator assessment includes the collection of Transmission assets over which the Planning Coordinator is responsible for coordinating planning (“PC Area”). The PC Area is normally comprised of more than one TP. Every Facility must have one associated Transmission Planner and at least one Planning Coordinator. This means that every Facility in the TP Area should be included in the assessment conducted by the TP.

As noted above, this typically aligns with the Transmission system facilities owned by an associated Transmission Owner(s). Because of the interconnected nature of the Bulk Electric System, the Transmission Planner works with other Transmission Planners to periodically update power system models used to perform simulations. Information needed to update these models is collected from various functional entities within a particular Transmission Planner’s area of purview. Power system modeling data is also “rolled up” by the Transmission Planner(s) to the Planning Coordinator to support development of Interconnection level models.[3] ~~, *i.e.*, those facilities for which the Transmission Planner develops reinforcement and corrective action plans resulting from studies and analysis of system performance and interconnection of facilities. This means that the Transmission Planner’s area is not defined by the extent of the models it uses or studies that it performs since any planner can assess and perform simulations on readily available interconnection wide models. The BES facilities in its area, *i.e.*, under its purview, are generally contiguous.~~

[2] Definition of Transmission Planner (effective July 1, 2016) from the NERC Glossary of Terms. In the Glossary, Planning Coordinator and Planning Authority are defined interchangeably.

[3] In some instances, the same entity may serve as both a Transmission Planner and Planning Coordinator.

~~Traditionally transmission planning has been associated with one or more Transmission Owners, *i.e.*, reinforcement and corrective action plans must be associated with the facilities of certain Transmission Owners. In some cases where transmission ownership crosses a state line, the BES facilities on one side of a geographic boundary line may be in one Transmission Planner Area while the remaining facilities may be in another. As such, the Transmission Planner Area is not constrained to fit within one Reliability Coordinator or Transmission Operator Area. However, the Transmission Planner Area can only be smaller than or equal to the area of its related Planning Coordinator.~~

~~**Develop Transmission Expansion Plans.**~~ The Transmission Planner evaluates the impact of ~~facilities that will be needed in response to~~ long-term ~~requests for t~~Transmission ~~s~~Service requests, and the ~~needed to~~ integration~~e~~ of new generation, ~~t~~Transmission, and end-use customers, ~~into the Bulk Electric Systems~~on the planned Transmission system performance. In evaluating requests ~~developing plans~~ for long-term ~~t~~Transmission ~~s~~Service or~~and~~ new interconnections ~~requests~~, the Transmission Planner is expected to coordinate ~~plans or engage in joint planning~~ with other Transmission Planners, as appropriate, to ensure new service/facilities do not adversely affect the reliability of neighboring ~~t~~Transmission systems.

~~Based on customer requests for transmission service, native load growth, changes in existing native load, and the planning procedures and protocols established for their Transmission Planning Areas, the Transmission Planners will develop transmission plans to accommodate long-term firm transmission service requests and native load requirements with due regard to established reliability needs. While developing these plans, the Transmission Planner may provide alternate solutions and evaluate alternatives suggested by entities requesting customer service.~~

The Transmission Planner~~s~~ provides its assessment results ~~transmission plans~~ to ~~its~~ the appropriate Planning Coordinator for review to ensure that the impacts on the interconnected systems are duly addressed. In reporting its ~~transmission expansion plan~~assessment results to the Planning Coordinator, the Transmission Planner is expected to assess whether its plans for new or reinforced facilities meet reliability needs or whether corrective plans are necessary. The Transmission Planners work with the Planning Coordinator to identify potential alternative solutions, including solutions proposed by stakeholders, to meet interconnected Bulk Electric System requirements.

Part 5 - Resource Planner

The Resource Planner develops a long-term (generally 1 year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Resource Planner area. Note: The term "resource" is to be understood to include supply resources and demand-side resources (such as dispatchable loads).

The boundaries for the Resource Planner area are basically defined by the location of the specific loads being considered for resource adequacy. The loads under considerations are generally contiguous and form the fundamental input for analysis of resources such as loss of load studies. The Resource Planning function may be performed by one or more Resource Planners within a Planning Coordinator area, Transmission Planner or Reliability Coordinator Area; however, the Resource Planning Function could be performed by one Resource Planner that covers one, or more than one, Planning Coordinator area, Transmission Planner Area or Reliability Coordinator Area. As such the Resource Planner area is not constrained to fit within the footprint of any other functional entity. The analysis and development of resource plans by their very nature will need to consider generation capacity and other resources outside the area defined by the specific loads as well as the transmission capability to access those resources.

In some markets, market rules may require the same organization to assume the role of both the Planning Coordinator and the Resource Planner. For example, in those markets where there are no entities responsible for or obligated to serve load, the Planning Coordinator will generally assume the Resource Planner's role. In these cases, the Planning Coordinator identifies the need for additional resources to be provided by the market and performs the Resource Planning Function.

Types of Resource Planning

Resource planning, in a generic sense, may be divided into two types:

- Planning conducted by an organization under the authority of legislation, regulation order, tariff or market rule. Such planning will typically be conducted in an open process and subject to industry, public and stakeholder review. It will have as one objective, ensuring resource adequacy.
- Planning directed to identifying and realizing commercial opportunities. Such plans will typically be commercially sensitive, may not be made public before required for the plan to be implemented, and will not be directed to ensuring resource adequacy.

The Resource Planner described in the Model is associated with the former type of planning, *i.e.*, planning having a mandate to ensure resource adequacy.

The latter type of planning, which is driven primarily by commercial opportunity, may be viewed as an activity associated with generation ownership. However, resource planning that is purely commercially-driven clearly will have an impact on resource adequacy. The Resource Planner, with its mandate for resource adequacy, must reflect to the extent possible commercially-directed planning affecting its Resource Planner area.

Part 6 - Transmission Operator

The Transmission Operator acts or authorizes action to connect to, disconnect from or reconfigure (switching operations) Facilities classified as Transmission assets, as described by the following:

a. Actions may include direct or indirect control of Transmission assets from a Control Center-to conduct operations during Normal and Emergency conditions.

b. Authorizations to act may include orders directing designated field personnel with Transmission System switching responsibilities to perform switching operations on Facilities classified as Transmission assets during Normal and Emergency conditions.

The Transmission Operator ~~operates or directs the operation of transmission facilities, and~~ maintains local-area reliability, that is, the reliability of the system and area for which the Transmission Operator has responsibility. The Transmission Operator achieves this by operating the ~~t~~Transmission system within its purview in a manner that maintains proper voltage profiles and System Operating Limits, and honors ~~t~~Transmission equipment limits established by the Transmission Owner. The Transmission Operator is under the Reliability Coordinator's direction respecting wide-area reliability considerations, that is, considerations beyond those of the system and area for which the Transmission Operator has responsibility and that include the systems and areas of neighboring Reliability Coordinators. The Transmission Operator, in coordination with the Reliability Coordinator, can take action, such as implementing voltage reductions, to help mitigate an Energy Emergency, and can take action in ~~s~~System restoration.

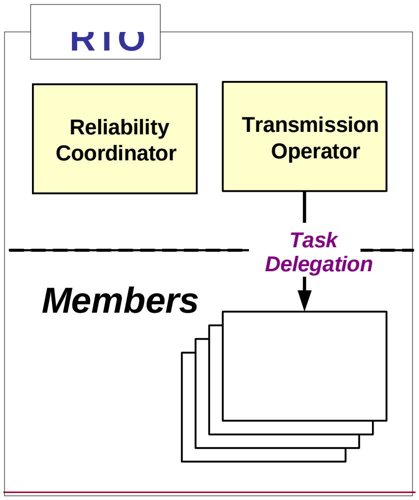
~~Note that the Model does not attempt to define what is and isn't a transmission facility, versus a generating facility. As discussed in Section II-13, this is assumed to be defined elsewhere by NERC or by governmental authorities.~~

~~**Maintenance**. The Transmission Owner provides the overall maintenance plans and requirements for its equipment, specifying, for example, maintenance periods for its transformers, breakers, and the like. The Transmission Owner then develops or arranges for the development of the detailed maintenance schedules (dates and times) based on the Transmission Owner's maintenance plans and requirements, and provides those schedules to the Reliability Coordinator and others as needed.~~

~~The organization serving as Transmission Operator may also physically provide or arrange for transmission maintenance, but it does this under the direction of the Transmission Owner, which is ultimately responsible for maintaining its owned transmission facilities.~~

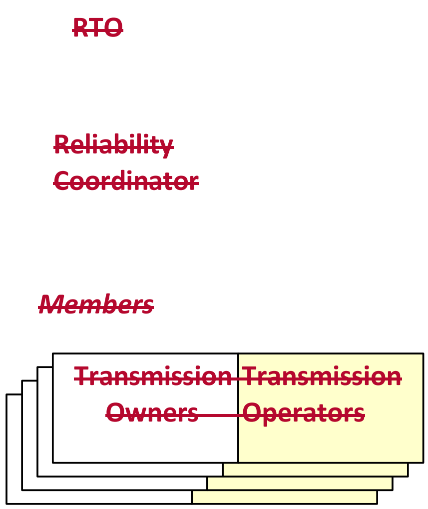
~~**Bundled with the Reliability Coordinator or Transmission Owner**. A single organization may be the functional entity for multiple Functions. In such a case, the functional entities are said to be "rolled up" or "bundled" into a single organization. An organization may be a Transmission Operator without being a Reliability Coordinator or Transmission Owner. However, in many cases the Transmission Operator is bundled with one of these functional entities.~~

~~**Bundled with Reliability Coordinator**. For example, consider an RTO with several members. The RTO registers with NERC as a Reliability Coordinator and Transmission Operator and is NERC-certified for both. The RTO then delegates/assigns some of the Transmission Operator Tasks to its members.~~



~~***Figure 1 - Transmission Operator bundled with Reliability Coordinator***~~

~~**Bundled with the Transmission Owner**. In other situations, the RTO registers with NERC as the Reliability Coordinator, and its members register as Transmission Owners and Transmission Operators, as shown in Figure 2. In this case, the Model views the RTO as responsible for complying with Reliability Standards associated with the Reliability Coordinator and would be NERC-certified as such. The RTO members would be responsible for complying with all Reliability Standards associated with the Transmission Operator, and would be NERC-certified as such.~~



~~***Figure 2 – Transmission Operator bundled with Transmission Owner***~~

Part 7 - Interchange Coordinator

The e-tagging process exists for scheduling Transmission usage by entities who have contracted for Transmission access. NAESB maintains the e-tagging specification. The Interchange Coordinator is equivalent to the tag authority described in the specification. (NAESB states this service has been assigned to the Sink Balancing Authority. The functional model envisions that the Sink Balancing Authority may serve as its own Interchange Coordinator or have this service provided by a separate organization.)

The "authority service"[4] is the focal point for all interactions with an e-Tag and maintains the single authoritative "copy of record" for each e-Tag received. Every Sink Balancing Authority is responsible for registering the URL of an "authority service." The authority service forwards all valid received RFI to each entity identified in the transaction as having "approval" or "viewing" rights over that RFI, and collects approvals/denials issued by these approval services. Based on time and the message(s) received from the approval services, the authority service arbitrates and sends the final disposition of the request to each entity in the distribution list. The authority service also provides the capability for both the agent (requestors of service) and approval services to interrogate the current approval state of any transaction RFI on demand.

~~The Interchange Coordinator collects approvals or denials for Arranged Interchange from Balancing Authorities and Transmission Service Providers and verifies the validity of the source and sink. The NERC Tag Authority provides this service that had been assigned to the Sink Balancing Authority.~~

~~The Interchange Coordinator provides the Balancing Authority with the individual bilateral Arranged Interchange. The Balancing Authority must track the individual Interchange Schedules in case one or more of them are curtailed by the Reliability Coordinator or by the Balancing Authority in those cases where a generator or load is interrupted. The Balancing Authority then creates a "net" interchange total for use in its energy management system as well as a "net" interchange for each neighboring Balancing Authority. The net Interchange Schedule for each neighboring Balancing Authority is used by the Receiving Balancing Authority for checkout with the neighboring Balancing Authorities.~~

~~All bilateral Interchange Transactions *that cross a Balancing Authority Area boundary* are coordinated through the Interchange Coordinator.~~

~~While the approval/denial process may utilize tools (such as computer software and communication protocols), the Model envisages that the Interchange function will be assigned to an actual organization. A Balancing Authority may serve as its own Interchange Coordinator or have this service provided by a separate organization.~~

~~**Assessing ramping capability and connectivity**. The Balancing Authority approves/denies the capability to ramp the Arranged Interchange in or out and notifies the Interchange Coordinator. The connectivity of adjacent Balancing Authorities is also verified by the Balancing Authorities before responding to the~~

[4] Definitions from NAESB:
e-Tag Agent Service: Software component used to generate and submit new e-Tags, corrections, and profile changes to an e-Tag Authority Service and to receive state information for these requests.
e-Tag Authority Service: Software component that receives e-Tag Agent Service and e-Tag Approval Service requests and responses and forwards to the appropriate approval service. Also maintains master copy of e-Tag (all associated requests), the composite state of the e-Tag, etc. and responds to queries regarding the e-Tags in its possession.
e-Tag Approval Service: Software component used to indicate individual approval entity responses when requested by the e-Tag Authority Service, as well as submit profile changes.

~~Interchange Coordinator.~~

~~**Ensuring balanced, valid Interchange Transactions**. The Interchange Coordinator also ensures that the resulting Confirmed Interchange Transactions is balanced and valid prior to physical delivery. This means:~~

- ~~The source MW must be equal to the sink MW (plus losses if they are "self-provided"), and~~
- ~~All reliability entities involved in the Arranged Interchange are currently in the NERC registry.~~

~~Only when it receives approvals from the Transmission Service Providers and Balancing Authorities, does the Interchange Coordinator direct the Balancing Authorities to implement the Transaction. If any of these entities -TSPs or BAs - does not approve the Arranged Transaction, then the Interchange Coordinator does not authorize the Transaction to become Confirmed Interchange.~~

~~**Curtailments**. The Interchange Coordinator coordinates curtailments of Confirmed Interchange ordered by the Reliability Coordinator by notifying the Balancing Authorities, Transmission Service Providers, and Purchasing-Selling Entities. The Interchange Coordinators also communicates and coordinates the resulting modified Arranged Interchange that result from the curtailments.~~

Part 8 - Transmission Service Provider

The Transmission Service Provider authorizes the use of the transmission system under its authority. In ~~most~~ some cases, the organization serving as Transmission Service Provider is also the market operator.

Role in approving Interchange. The Transmission Service Provider approves Arranged Interchange by comparing the ~~t~~Transmission ~~s~~Service previously arranged by the ~~t~~Transmission ~~c~~Customer (Purchasing-Selling Entity, Generator Owner, Load-Serving Entity) with the ~~t~~Transmission information supplied by the Interchange Coordinator. The Transmission Service Provider also ensures that there is a contiguous ~~t~~Transmission path and that adjacent Transmission Service Providers~~SPs~~ are on the ~~s~~Scheduling ~~p~~Path. The Transmission Service Provider then provides its approval or denial to the Interchange Coordinator.

Providing Transmission and Ancillary Service. As its name implies, the Transmission Service Provider provides transmission service and Ancillary Service to transmission customers, such as Generator Owners, Load-Serving Entities, and Purchasing-Selling Entities. The Transmission Service Provider determines Available Transfer Capability based on the established Total Transfer Capabilities, System Operating Limits and Interconnection Reliability Operating Limits (by various entities including the Planning Coordinator, Transmission Planner, Transmission Operator and Reliability Coordinator), and coordinates ATC with other Transmission Service Providers. The Transmission Service Provider manages the requests for transmission service according to the Transmission Owner's tariff, and within the operating reliability limits determined by the Reliability Coordinator. The Transmission Service Provider ensures necessary Ancillary Services are provided to the Transmission Operator and Balancing Authority. The Transmission Service Provider does not itself have a role in maintaining system reliability in ~~r~~Real time — that is done by the Reliability Coordinator and Transmission Operator and Balancing Authority.

The Transmission Service Provider arranges for transmission loss compensation and Ancillary Service requirements with the Balancing Authority.

Part 9 - Transmission Owner

The Transmission Owner owns its transmission facilities and provides for the maintenance of those facilities. It also specifies equipment operating limits, and supplies this information to the Transmission Operator, Reliability Coordinator, and Transmission Planner and Planning Coordinator.

In many cases, the Transmission Owner has contracts or interconnection agreements with generators or other transmission customers that would detail the terms of the interconnection between the owner and customer.

~~**Relationship with the Transmission Operator**. The organization serving as Transmission Owner may operate its transmission facilities or arrange for another organization (which may or may not be a Transmission Owner) to operate and/or maintain its transmission facilities.~~

Maintenance. The Transmission Owner provides the overall maintenance plans and requirements for its equipment, specifying, for example, maintenance periods for its transformers, breakers, and the like. The Transmission Owner then develops or arranges for the development of the detailed maintenance schedules (dates and times) based on the Transmission Owner's maintenance plans and requirements, and provides those schedules to the Reliability Coordinator and others as needed.

The organization serving as Transmission Operator may also physically provide or arrange for transmission maintenance, but it does this under the direction of the Transmission Owner, which is ultimately responsible for maintaining its owned transmission facilities.

~~See "Transmission Operator," Section "Bundling with the Reliability Coordinator or Transmission Owner"~~

Part 10 - Distribution Provider

The Distribution Provider provides the physical connection between the end-use customers, distribution-connected energy resources, and the BES~~electric system~~, including customers served at ~~t~~Transmission level voltages. The Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage. One Distribution Provider may be directly connected to another Distribution Provider, such connections must be reported to the Balancing Authority even though ~~and~~ not directly connected to the BES~~ulk Electric System~~.

The Distribution Provider maintains "local" safety and reliability and is responsible for the distribution facilities to serve end-use customers and distribution-connected energy resources. The Distribution Provider provides the switches and re-closers necessary for emergency action and information necessary for the Transmission Operator and Transmission Planner. The Distribution Provider may need to demonstrate manual ~~l~~Load-shedding capability to the Balancing Authority and Transmission Operator. Design and maintain protective relaying systems, under-frequency load-shedding systems, under-voltage Load-shedding systems, and Remedial Action Schemes that interface with the Transmission system.

~~The same organization may serve as the Distribution Provider and Load-Serving Entity, but they may be separate organizations as well.~~ Unlike the Load-Serving Entity, the Distribution Provider has the facilities or assets ("wires") and does not take title to any energy. However, while these functions are distinct, in many cases an organization, such as a vertically integrated utility, bundles these functions together.

~~Part 11 - Generator Operator~~

~~The Generator Owner may operate its generating facilities or designate a separate organization to perform the Generator Operation Function.~~

~~The Generator Operator operates, or directs the operation of generation facilities. The Generator Operator supports the needs of the Bulk Electric System up to the limits of the generating facilities in its purview. Ultimately the Generator Operator's role is to meet generation schedules, manage fuel supplies, and provide frequency support and reactive resources without jeopardizing equipment.~~

~~**Relationship with the Generator Owner.** The organization that serves as Generator Operator may also be the owner of the generation facilities it operates, or it may be a separate organization designated by the Generator Owner to operate the facilities. The Generator Operator receives maintenance and performance verification schedules from the Generator Owner, and develops operating and unit commitment plans based on these schedules~~

~~**Relationship with the Transmission Operator.** The Generator Operator provides reliability- related services through arrangements or by direction from the Transmission Operator for support of the Bulk Electric System. The Generator Operator provides maintenance schedules, generator status, and AVR status to the Transmission Operator. The Generator Operator receives notification of transmission system problems affecting its generator from the Transmission Operator or Reliability Coordinator.~~

~~**Relationship with the Balancing Authority.** The Generator Operator provides unit commitment schedules, generator status, and operating and availability status of generating units to the Balancing Authority.~~

~~**Relationship with the Reliability Coordinator.** The Generator Operator provides annual maintenance plans, and operational data to the Reliability Coordinator. The Generator Operator takes actions based on directives from the Reliability Coordinator for the needs of the Bulk Electric System.~~

~~**Relationship with Purchasing-Selling-Entity.** The Generator Operator receives notice of Arranged Interchange approved by the Purchasing-Selling-Entity.~~

~~Part 12 - Generator Owner~~

~~The Generator Owner owns its generation facilities and provides for the maintenance of those facilities.It also provides verified equipment operating limits and supplies this information to the Generator Operator, Reliability Coordinator, Transmission Planner and Planning Coordinator.~~

~~In many cases, the Generator Owner has contracts or interconnection agreements with Transmission Owners or Distribution Providers that detail the terms of the interconnection between these parties.~~

~~**Relationship with the Generator Operator**. The organization serving as Generator Owner may operate generation facilities, or arrange for another organization to do so. In addition, the organization serving as Generator Owner may perform maintenance and facility verification, or may arrange with another organization to do so.~~

~~Part 13 - Purchase-Selling Entity~~

~~The Purchasing-Selling Entity (PSE) arranges for and takes title to energy products (capacity, energy and reliability-related services) that it secures from a resource for delivery to a Load- Serving Entity (LSE). The PSE also arranges for transmission service with the Transmission Service Provider that provides transmission service to the LSE under a tariff or market rule.~~

~~The Purchasing-Selling Entity initiates a bilateral Interchange between Balancing Authority Areas by submitting a Request for Interchange (RFI) to the Interchange Coordinator.~~

Part 14 - Load-Serving Entity

The Load-Serving Entity (LSE) arranges for the provision of energy Resources and Ancillary Services to its Balancing Authority and Resource Planner in order to supply its end-use customers, but does not provide distribution services (“wires”). ~~The LSE defined in the Model is not to be confused with or equated to the LSE as defined in any tariff or market rule.~~

~~Today, o~~Organizations serving as Load-Serving Entities may also be Generation Owners and can self-provide, or have contracts with other Generator Owners for capacity, ~~and~~ energy and Ancillary Services to serve the Load-Serving Entity~~’s~~ customers, or purchase capacity,~~ and~~ energy, and Ancillary Services from non-affiliated Generator Owners through a Purchasing-Selling Entity (or Market Operator), or employ a combination of these three options.

The Load-Serving Entity reports its ~~generation~~ resource (affiliated and non-affiliated) arrangements to serve load to the Balancing Authority, which forwards this information to the Reliability Coordinator, for day-ahead analysis.

The LSE may contract for ~~reliability-related services~~ Ancillary Services through the Transmission Service Provider or the ~~M~~market ~~O~~operator (if the Load-Serving Entity is part of a market or pool) or directly from Generator Owners or loads.

~~The same organization may serve as the Distribution Provider and Load-Serving Entity, but they may be separate organizations as well.~~ Unlike the Distribution Provider, the Load-Serving Entity, does not have Bulk Electric System assets (“wires”) but does take title to energy. However, while these functions are distinct, in many cases an organization, such as a vertically integrated utility, bundles these functions together.

~~The Functional Model assigns to t~~The Load-Serving Entity is responsible for the identification of loads for ~~c~~Curtailment and those critical customer loads that are to be excluded from the load-shedding systems, and the development of load profiles and load forecasts. ~~Please see Section II, 114: Roles in Load Curtailment for more detailed information.~~

The Load-Serving Entity communicates requests for ~~voluntary c~~Curtailment to the appropriate end-use customer loads~~, thereby ensuring that these loads will in fact be curtailed~~.

~~Part 15 - Compliance Enforcement Authority~~

~~NERC is the Compliance Enforcement Authority. The Regional Entities have a major role in the actual performance of the monitoring, under delegated authority from NERC.~~

~~Part 16 - Standards Developer~~

~~The Standards Developer is written to be NERC. The Reliability Standards referenced in the Model consist of standards developed by either NERC or a Regional Entity and that are approved by NERC and subsequently by governmental authorities. This would therefore not include regional reliability criteria that are not submitted to NERC for approval. This is discussed further in Section II.~~

~~Part 17 - Market Operator (Resource Integrator)~~

~~Market Operations is not a reliability Function. It is included in the Model to provide a linkage between reliability Functions and commercial functions. The associated functional entity is the Market Operator (Resource Integrator). The term Resource Integrator replaces Resource Dispatcher used in Version 3 of the Model. This recognizes that integration of resources is the essential feature, not resource dispatch, which is the responsibility of the Balancing Authority.~~

~~The Market Operator is described further in Section II, Technical Discussions.~~

Part 18 - Reliability Assurer

The Reliability Assurer is subject to oversight by the Federal Energy Regulatory Commission and governmental authorities in Canada. The Reliability Assurer assures the reliability of the Bulk Power System in North America by developing and enforcing Reliability Standards; annually assessing seasonal and long-term reliability; monitoring the Bulk Power System through system awareness; and, educating, training, and certifying industry personnel.

~~In Version 4 of the Model, the Reliability Assurer entity and the Reliability Assurance Function replaced Version 3's Regional Reliability Organization entity and the Regional Reliability Assurance Function.~~

~~The change to Reliability Assurer reflected the fact that a name specific to the Model is preferable to a name already in use in another context. Moreover, since this Function can be performed on other than a regional basis, the Functional Model allows for the assignment to be made to an organization other than a Regional Entity.~~

~~The changes therefore provide NERC with flexibility in assigning the functional entity for Reliability Assurance.~~

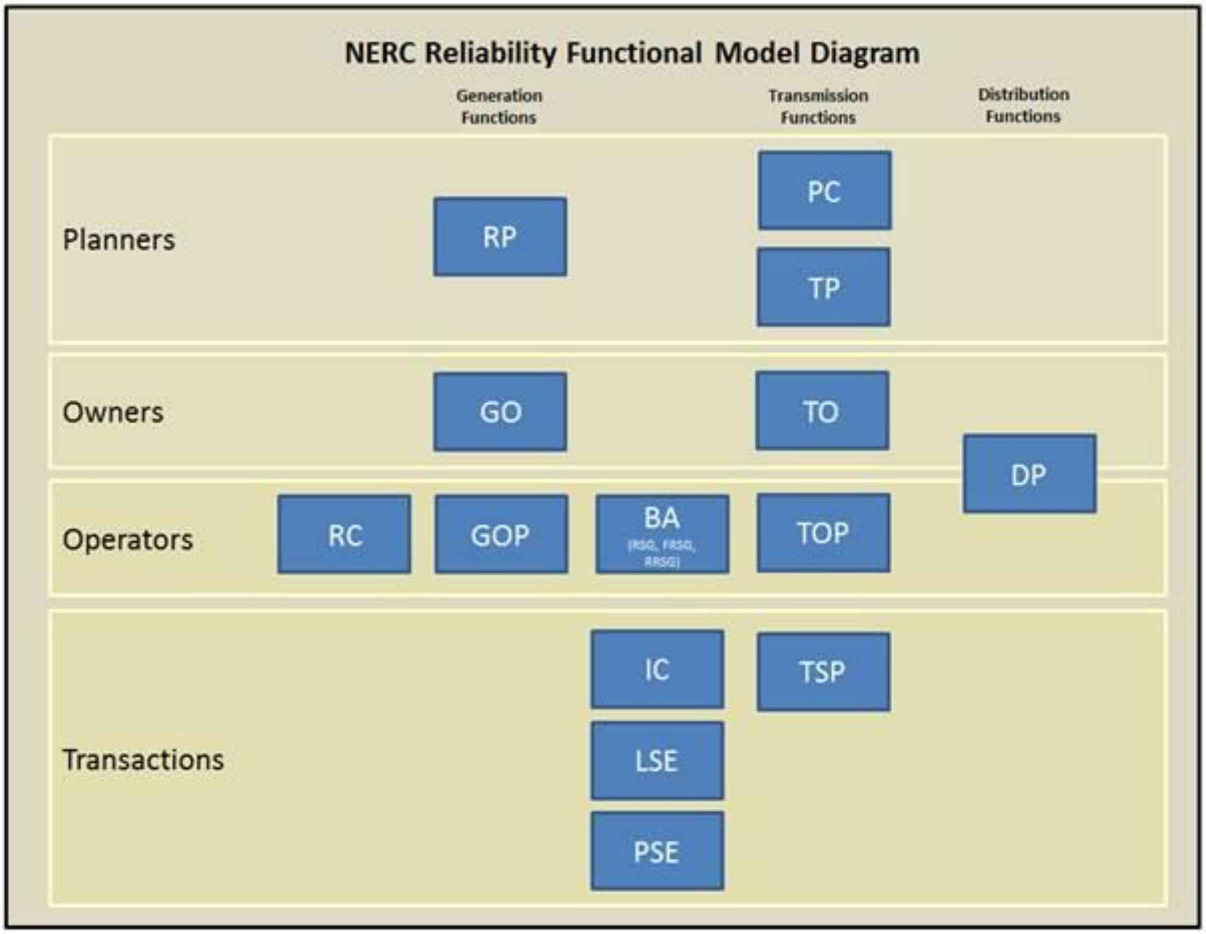
~~The role of the Reliability Assurer may be considered to provide "defense-in-depth." That is, the Reliability Assurer provides an independent assessment of Tasks performed by other functional entities, or facilitates or coordinates such Tasks. While the specific role of the Reliability Assurer is not fully developed at the present time, the following are representative of the Tasks that might be performed:~~

- ~~Perform high level evaluations, such as at a regional or Interconnection level, of transmission and resource adequacy. These evaluations may be based on a review of the plans of Transmission Planners.~~
- ~~Develop regional reliability plans, to ensure there are no reliability gaps, or no missing or ambiguous responsibilities or relationships.~~
- ~~Perform high-level evaluations, such as at a regional or Interconnection level, of protection systems as they relate to the reliability of the Bulk Electric System.~~
- ~~Perform disturbance analysis evaluations.~~

~~The selection of particular Tasks for the Reliability Assurer will reflect NERC's judgment on which Tasks merit such a "defense-in-depth" approach.~~

SECTION 2 – TECHNICAL DISCUSSION

The below diagram provides an illustration of how the various functional entities can be categorized.



~~Part 1 – General Clarifications of the Functional Model~~

~~The general features of the Functional Model are described in the Introduction, Purpose and Guiding Principles sections of the Model. In brief:~~

~~The NERC Reliability Functional Model ("the Model") provides the framework for the development and application of NERC's Reliability Standards, as follows:~~

- ~~The Model describes a set of Functions that are performed to ensure the reliability of the Bulk Electric System. Each Function consists of a set of related reliability Tasks. The Model assigns each Function to a functional entity, that is, the entity that performs the Function's Tasks. The Model also describes the interrelationships between that functional entity and other functional entities (that perform other Functions).~~

- ~~NERC's Standard Development Teams develop Reliability Standards that assign each reliability requirement within a standard to a functional entity, as defined in the Model.~~
- ~~This is possible because a given standard requirement will be logically related to a Task within a Function. A standards requirement will be very specific whereas a Task will be more general in nature.~~
- ~~NERC's compliance processes require specific organizations to register as functional entities and comply with standards requirements assigned to the functional entities.~~
- ~~The Model's Functions and functional entities also provide for consistency and compatibility among different Reliability Standards.~~

~~The NERC Reliability Functional Model ("the Model") does NOT address:~~

- ~~Entity Certification~~
- ~~Registration~~
- ~~Compliance~~
- ~~Sanctions~~

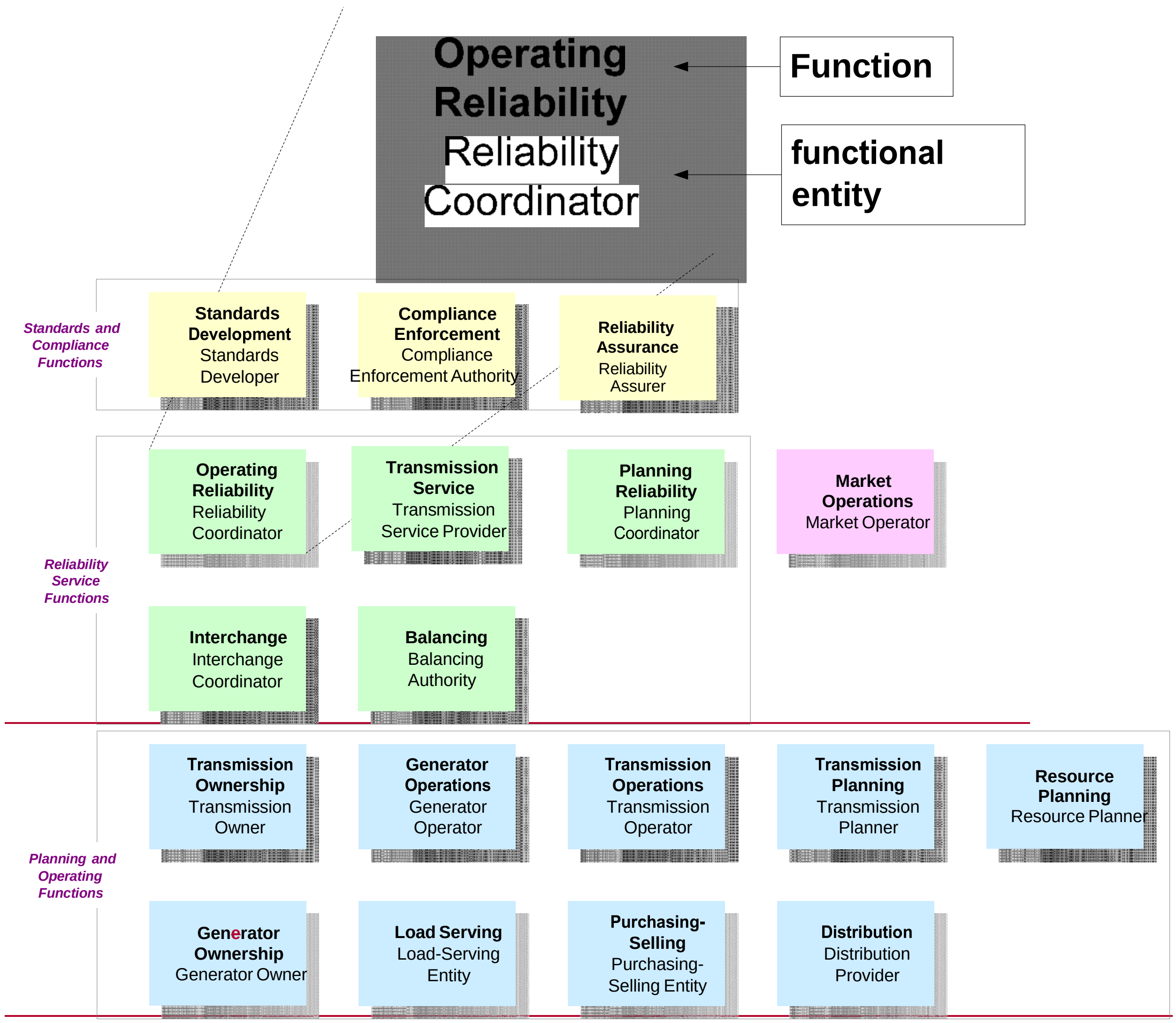
~~There are a number of clarifications that are important for those involved in developing standards and monitoring compliance with them. These clarifications are generally made in the Model itself, but because of their importance and potential for misinterpretation, they warrant being repeated.~~

~~**The Model is a guideline, it is not prescriptive.**~~ ~~The Model is not a standard, and does not have compliance requirements. The Model is a guideline for the development of standards and their applicability; it is not a NERC requirement. Standards developers are not required to include tasks envisioned in the model, nor are the developers precluded from developing Reliability Standards that conflict with the Model. The Reliability Standards requirements take precedence over the Model.~~

~~**A Functional Entity is not an actual organization.**~~ ~~The Model describes Tasks performed by functional entities, which are in effect generic *classes or categories* of organizations. The Model itself does not address *specific* organizations. The Model, for example, describes the Reliability Coordinator, a functional entity; the Model does not reference PJM and MISO, which are specific organizations. It is through the NERC registration process that the PJM and MISO organizations become a member of the category of organization called Reliability Coordinator, and thereby responsible for meeting standards requirements specified for the Reliability Coordinator.~~

~~Reliability is best served if there is consistency of definitions within all NERC documents. These documents include, but are not limited to, the Functional Model, the NERC Rules of Procedure and Glossary of Terms.~~

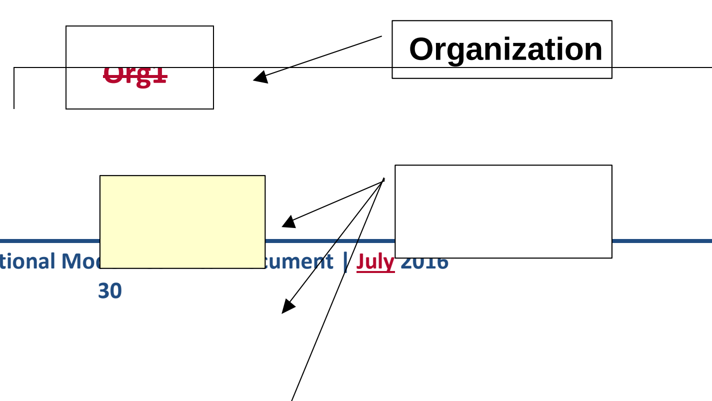
~~**Every Function has an associated functional entity.**~~ ~~A Function is a set of related reliability Tasks; whereas the functional entity is the name given to the category of organization that performs these Tasks. The diagram (Figure 3) of the Model includes two names within each Function box. The Function is shown in a larger typeface with the associated functional entity underneath.~~

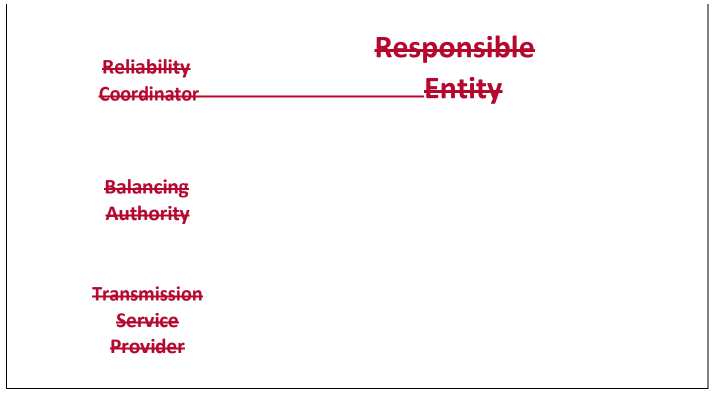


~~Figure 3 – Function and Functional Entity~~

~~Organizations, such as Regional Transmission Organizations or integrated utilities, may register with NERC as Responsible Entities by identifying which Functions they perform.~~

~~For example, as shown in Figure 4 an RTO (organization) may register with NERC to be a Reliability Coordinator, Balancing Authority, and a Transmission Service Provider. In this case we say that the RTO is the~~ **~~Responsible Entity~~** ~~for the Operating Reliability, Balancing, and Transmission Service Functions. We also use the expression that the RTO has "rolled up" these three Functions and is responsible for ensuring that the Tasks within each of those Functions are performed and all applicable standards requirements met.~~




~~Responsible Entity~~
~~Reliability Coordinator~~
~~Balancing Authority~~
~~Transmission Service Provider~~

~~Figure 4 — Organizations may "roll-up" more than one functional entity.~~

~~Part 2 - Reliability Standards~~

~~The Functional Model describes the Standard Development Function and the Standards Developer functional entity and how these are related to Reliability Standards.~~

~~Reliability Standards can be developed at the North American level as well as at the regional level and can therefore be placed in two categories:~~

~~Reliability Standards Developed at the North American Level Within NERC~~

~~NERC, under regulatory authority, develops and maintains Reliability Standards using the NERC Reliability Standards Development Procedures. The standards are applicable across North America upon approval by governmental authorities, unless specifically stated otherwise within the standard, and enable NERC and Regional Entities to monitor and enforce compliance with the standards requirements.~~

~~NERC can use the Reliability Standards Development Procedures to approve a variance from a NERC Reliability Standard; the variance then becomes part of the standard. The three categories of variance are:~~

- ~~Entity Variance that applies to an area less than a NERC Region~~
- ~~Regional Variance that applies to a NERC Region but less than an Interconnection~~
- ~~Regional Variance that applies to a NERC Region on an Interconnection-wide basis.~~

~~1. Reliability Standards Developed Within a Regional Entity~~

~~Regional Entities may develop and propose to NERC regional reliability standards that:~~

- ~~Set more stringent reliability requirements than the NERC Reliability Standard~~
- ~~Cover matters not covered by an existing NERC Reliability Standard.~~

~~Alternatively, NERC may direct Regional Entities to develop a regional reliability standard in order to implement a NERC Reliability Standard. Such a regional reliability standard, upon approval by NERC, becomes part of the NERC Reliability Standard.~~

~~Regional Entities must use a NERC-approved development process to develop these regional reliability standards. Such regional reliability standards, upon approval by NERC, become NERC Reliability Standards. As appropriate, NERC will approve the regional reliability standard as an:~~

- ~~Interconnection-wide regional standard, or~~
- ~~Non-Interconnection-wide regional standard.~~

~~Regional Criteria.~~ ~~Regional Entities may develop regional reliability criteria that are necessary to implement, to augment or to comply with Reliability Standards, or to address issues not within the scope of Reliability Standards. Such criteria are not approved by NERC and are not (NERC) Reliability Standards. As such, regional criteria, while clearly serving a reliability purpose, are best considered to be outside of the (NERC) Functional Model.~~

Part 1~~3~~ - Market Operations (Resource Integration)

Market Op~~Op~~erations is not a reliability ~~F~~function.~~ NERC does not assign standards requirements to the Market Operator.~~ Nevertheless, ~~M~~market ~~O~~operations, a commercial or market function, is included in the Functional Model, in order to provide an interface point between reliability and commercial functions.

The role of the ~~M~~market ~~O~~operator[5] also varies in design and responsibilities depending on whether resources are dispatched within a full-service market or where there is not a full-service market. However, ~~,~~ ~~but~~ all ~~M~~market ~~O~~operators perform a resource integration task of one form or another under a resource integration protocol~~ set of market rules~~ that is~~ are~~ recognized by a state, federal, or provincial regulator. A resource integration protocol is the method used to determine the merit order of the generation to be dispatched. Generally, resource integration protocols are either cost-based or bid-based, depending on the market rules established by the regulatory authority. The basis and results for the resource integration algorithms are generally the same for cost-based and bid-based dispatch, which is why the Functional Model accommodates either type of protocol. ~~Resource integration is discussed further in the following section II-4, Functional Model and Market Structures.~~

Multiple Balancing Authorities Within a Market Area. If the market area includes more than one Balancing Authority Area, then the market operator will also provide each Balancing Authority with the Net Interchange Schedule that results from the resource plan ("Resource Dispatch Interchange Schedule", or RDIS). Each Balancing Authority's RDIS will be an import or export to the Balancing Authority Area, and the sum of all RDISs within the market area must add to zero at each dispatch cycle.

Resource integration is discussed below for the cases of a full-service market and where there is no full-service market. ~~Versions 4 and 5 of the Model refer to the entity as "Market Operator (Resource Integrator)", where Resource Integrator is seen as a better term than Market Operator in areas not having a full-service market. For simplicity, the discussion below uses only the term Market Operator, to apply even where there is not a full-service market.~~

1. The Market Operator in a Full-Service Market~~.~~

A full-service market is one which offers both the commercial services such as integrating resources ahead of Real-time and settlement after the completion of Implemented Interchange and dispatch cycles, and implement the resource plan in Real-time, making adjustment as necessary to meet other reliability requirements not envisaged during the resource integration process (for example, reliability constraints). ~~In a full service market, the Market Operator tasks involve integrating resources in accordance with established market rules. Following its market rules and using available market mechanisms, the Market Operator integrates market resources by establishing a generation dispatch plan to meet the load forecast for the upcoming dispatch cycle (typically five minutes or longer).~~

~~This generation dispatch plan is usually a function of the generators' incremental bids ("merit order"). The established generation dispatch plan is submitted to the Balancing Authority for implementation. When the plan is tested for implementation, and limitations caused by transmission congestion are identified, the Balancing Authority will adjust the dispatch schedules accordingly. This constitutes a "security-constrained" dispatch.~~

[5] For simplicity, only the term "market operator" is used; this is intended to apply even where there is not a full-service market.

Bid-Based Resource Integration. In those areas of North America having a full-service market, market protocols provide Generator Owners the ability to bid into the market. In those cases, Generator Owners will direct the submission of bids via the Generator Operators to the Market Operator. The Market Operator, in turn, provides the Balancing Authority with the generator dispatch plan, so that the generators within the market footprint would be instructed to operate at the same incremental bid. Transmission constraints may cause the actual dispatch to deviate from the dispatch plan. Re-dispatch methods used to relieve the congestion may use: direct resource assignments, area / zonal dispatch signals, or bus-signals. The zonal and bus methodologies are often referred to as "Locational Marginal Pricing," or LMP.

Relationship between the Market Operator and Balancing Authority. In a full-service market, there is a close relationship between the ~~M~~market ~~O~~operator and the Balancing Authority. A full-service ~~M~~market ~~O~~operator performs resource integration tasks and is assigned the tasks of:

- Determining the generation dispatch plan (unit commitment) ahead of time
- Integrating scheduled interchange into that generation plan
- Designating which generators are available for regulation service
- Providing the generation dispatch plan to the Balancing Authority ahead of ~~r~~Real~~-~~time.

The Balancing Authority receives the plan, and implements it in real time.

2. The Market Operator Where There is not a Full-Service Market~~.~~

Cost-based Resource Integration. Where there is not a full-service market, the Market Operator will often be a traditional, vertically-integrated utility that acts also as Balancing Authority. The utility will dispatch its resources based on its incremental costs (fuel and operations and maintenance) and losses. The regulatory authority might specify the accounting rules for calculating these costs.
~~In jurisdictions not having a full-service market there will often be a traditional, vertically-integrated utility that may be both the Market Operator and the Balancing Authority, and most or all of the associated tasks will be performed internal to the utility. The generation dispatch plan will typically be cost-based, in contrast to bid-based dispatch in a full-service market.~~

In addition, there are jurisdictions that use a model other than full-service market and vertically-integrated utility, in particular bilateral Interchange Transactions. In this case, the organization serving as Balancing Authority will also be the ~~M~~market ~~O~~operator, operating on the basis of ~~n~~Net ~~i~~Interchange.

3. Summary: The Market Operator Using Different Structures

The table below describes how the current operating tasks may be performed by both the vertically-integrated utility and the unbundled, full-service market operator.

~~Part 4 – The Functional Model and Market Structures~~

~~This section explains how the Functional Model can accommodate different market structures by examining these structures from the perspective of resource integration protocol.~~

~~**Resource Integration Protocol**. A resource integration protocol is the method used to determine the merit order of the generation to be dispatched. Generally, resource integration protocols are either cost-based or bid-based, depending on the market rules established by the regulatory authority, as described in section II-3, Market Operations (Resource Integration). The basis and the results for the resource integration algorithms are generally the same for cost-based and bid-based dispatch, which is why the Functional Model can accommodate either type of protocol.~~

~~**Bid-Based Resource Integration**. In those areas of the U.S. and Canada having a full-service market, market protocols provide Generator Owners the ability to bid into the market. In those cases, Generator Owners will direct the submission of bids via the Generator Operators to the Market Operator. The market protocols are established by the governmental authority, such as the Federal Energy Regulatory Commission in the U.S. and provincial regulators in Canada. The Market Operator, in turn, provides the Balancing Authority with the generator dispatch plan, so that the generators within the market footprint would be instructed to operate at the same incremental bid. Transmission constraints may cause the actual dispatch to deviate from the dispatch plan. Re-dispatch methods used to relieve the congestion may use: direct resource assignments, area / zonal dispatch signals, or bus-signals. The zonal and bus methodologies are often referred to as "Locational Marginal Pricing," or LMP.~~

~~**Cost-based Resource Integration**. Where there is not a full-service market, the Market Operator may be a traditional, vertically-integrated utility that acts also as Balancing Authority. The utility will dispatch its resources based on its incremental costs (fuel and operations and maintenance) and losses. The regulatory authority, such as the state public utility commission, might specify the accounting rules for calculating these costs.~~

~~**Multiple Balancing Authorities Within a Market Area.** If the Market Area includes more than one Balancing Authority Area, then the Market Operator will also provide each Balancing Authority with the net "interchange" schedule that results from the resource plan ("Resource Dispatch Interchange Schedule", or RDIS). Each Balancing Authority's RDIS will be an import or export to the Balancing Area, and the sum of all RDISs within the Market Area must add to zero at each dispatch cycle.~~

~~The table below describes how the current operating tasks may be performed by both the vertically-integrated utility and the unbundled, full-service market operator.~~

Task	No Full-Service Market: Vertically Integrated Structure	Full-Service Market: Unbundled Structure
Unit Commitment	Utility (performing as the Generator Owner) decides which units to run.	Generator Owners decides which units to make available.

Economic Dispatch	Utility (as Market Operator or Resource Integrator) performs economic dispatch calculation based on incremental costs or other requirements. Utility must consider generator operating limits, which units are providing regulation service, and any commitments for bilateral arrangements.	Market Operator collects bids from Generator Owners and develops integrated resource plans based on market rules (*e.g.*, bids). Market Operator must consider generator operating limits, which units are providing regulation service, and any commitments for bilateral arrangements.
Congestion Management	Results in different incremental costs ("lambdas").	Depending on the market structure, results in Different locational marginal prices (LMP), or Different marginal costs
Regulation Service	Utility (serving as the Balancing Authority, Load-Serving Entity, and Generator Owner) in concert with the Reliability Coordinator, determines the amount of regulation service required, and designates those units that provide the regulation service. Utility (as Balancing Authority) uses this information in its economic dispatch.	Balancing Authority, along with Reliability Coordinator, determines the amount of regulation service required. Generator Owners decide which units to bid in for regulation service. Market Operator runs bid pool for regulation service. Load-Serving Entity arranges for regulation services.
Generator Control	Utility (as Balancing Authority) pulses units that are designated by the Market Operator for regulation service. As regulating ability declines, the part of the utility that acts as Balancing Authority directs the part of the utility that acts as Market Operator to develop a new dispatch plan.	Balancing Authority pulses units that are designated by the Market Operator for meeting energy and regulation service requirements. As regulating ability declines, the Balancing Authority asks the Market Operator for a new dispatch plan.

Part 2~~5~~ - Providing and Deploying Ancillary and Interconnected Operations Services~~Reliability-Related Services~~

The North American electric power system is transforming to a resource mix that relies less on coal and nuclear while integrating more natural gas, wind, solar, distributed generation, and demand response resources. Additionally, the power system will change further as micro-grids, smart networks, and other advancing technologies continue to be deployed. Recognizing that these changes represent a fundamental shift in the operational characteristics of the power system with potential reliability implications, the policies that govern Ancillary Services and the characteristics of Interconnected Operations Services may evolve to address these newer resources. Proper planning and providing system operators with the ability to manage resources in real time will be required to ensure that the appropriate levels of Interconnected Operations Services are available so that reliability is maintained as the resource mix evolves.

The Building Blocks of Reliability[6]

Based on the analysis of geographic areas that are experiencing the greatest level of change in their types of resources, a number of measures and industry practices are recommended to identify trends and prepare for the transition in resource mix. These recommendations consider both real-time operations and future planning to support frequency, ramping and voltage of the system.

Frequency – The electric grid is designed to operate at a frequency of 60 hertz (Hz). Deviations from 60 Hz can have destructive effects on generators, motors, and equipment of all sizes and types. It is critical to maintain and restore frequency after a disturbance such as the loss of generation. Frequency will immediately fall given such an event. This requires an instantaneous (inertial) response from some resources and a fast response from other resources to slow the rate of fall during the arresting period, a fast increase in power output during the rebound period to stabilize the frequency, and a more prolonged contribution of additional power to compensate for lost resources and bring system frequency back to the normal level.

Ramping – Adequate ramping capability (the ability to match load and generation at all times) is necessary to maintain system frequency. Changes to the generation mix or the system operator’s ability to adjust resource output can impact the ability of the operator to keep the system in balance.

Voltage – Voltage must be controlled to protect system reliability and move power where it is needed in both normal operations and following a disturbance. Voltage issues tend to be local in nature, such as in sub-areas of the Transmission and distribution systems. Reactive power is needed to keep electricity flowing and maintain necessary voltage levels.

[6] Excerpt from North American Electric Reliability Corporation (NERC) ERS Framework Report, December 2015

Tariff Domain — Requirement for Ancillary Services. ~~The FERC open access (pro forma) tariff requires the (U.S.) Transmission Provider to provide the following Ancillary Services to all customers taking basic transmission service (Figure 5):~~

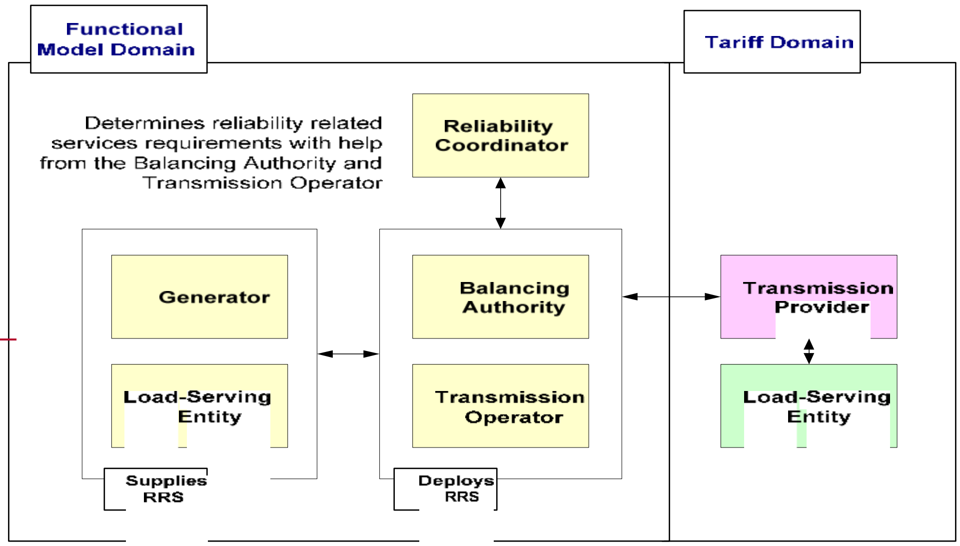


Figure 5 - Supply and Deployment of Ancillary Services and Reliability-Related Services.

The FERC pro-forma tariff requires that the Transmission Provider offer to provide Ancillary Services, as a provider of last resort, ~~the following services~~ to customers serving loads within the Transmission Provider's own area which do not purchase or self-provide:

1. Scheduling, system control, and dispatch
2. Reactive supply and voltage control from generation.
3. Energy imbalance
4. Regulation and frequency response
5. Operating reserve — spinning
6. Operating reserve — supplemental.
7. Generator Imbalance

Functional Model Domain — Interconnected Operations ~~Reliability-related~~ Services. A service (exclusive of basic energy and Transmission Services) that is required to support the Reliable Operation of interconnected Bulk Electric Systems.[7] ~~The term "reliability-related services" means those services other than the supply of energy for load that are~~ These Interconnected Operations Services are physically provided by generators, transmitters and loads in order to maintain reliability.

~~Reliability-related services include voltage control and reactive power resources from generators, transmitters and loads.~~ Certain ~~t~~Transmission facilities can provide reactive support, but are not considered an Ancillary Service in the open access tariff, rather, they are considered part of basic ~~t~~Transmission service. In addition, loads may provide reserves through load-shedding or ~~d~~Demand-~~s~~Side ~~m~~Management, and may also provide frequency response.

Ancillary Services in the “tariff domain” could be served by Interconnected Operations Services ~~reliability-related services~~ in the "reliability domain.” The Functional Model explains that the Balancing Authority, alone or

[7] Definition of Interconnected Operations Services from the NERC Glossary of Terms (as of May 15, 2016).

in coordination with the Reliability Coordinator, determines the amount required and arranges for Interconnected Operations Services ~~reliability-related services~~ to ensure balance:

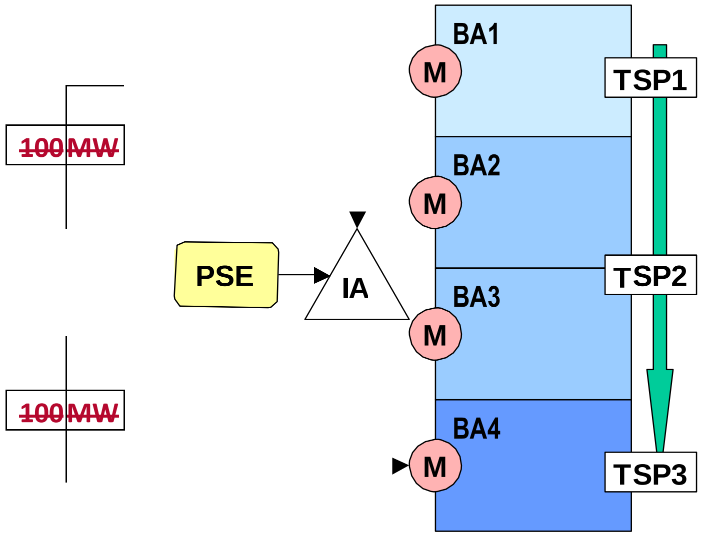
- The Balancing Authority determines regulation, load following, frequency response, ramping capability and contingency reserves, ~~etc.,~~ and deploys these as Interconnected Operations Services~~reliability-related services~~.
- The Transmission Operator determines the reactive resources ~~reliability-related services~~ necessary to meet its ~~r~~Reactive ~~p~~Power requirements to maintain ~~t~~Transmission voltage within operating limits, and deploys these as its set of Interconnected Operations Services~~reliability-related services~~.
- The Reliability Coordinator, working with the Transmission Operator, determines the need for black start~~Black Start~~ capacity. The Transmission Operator cannot do this alone, because it may not have a wide enough picture of the ~~t~~Transmission system.

~~Through its Reliability Standards, NERC holds organizations (those registered as Reliability Coordinators, Balancing Authorities, Transmission Operators and Transmission Service Providers) responsible to comply with applicable standards requirements, including those requirements that depend on reliability-related services.~~ The quantity of and processes used to deploy those Interconnected Operations Services ~~reliability-related services~~ depend on the ~~R~~regional and local system characteristics and regulatory requirements. The responsible organizations establish the quality and quantity of their own Interconnected Operations Services ~~reliability-related services~~, using these processes and procedures in a manner that ensures reliable operation of the BES~~compliance with the standards' requirements~~.

~~Part 6 - Managing Bilateral Interchange Transactions – Basic Concepts~~

~~Interchange that crosses multiple Balancing Authority (BA) Areas can be broken down daisy-chain fashion into individual Balancing Authority-to-Balancing Authority Interchange Transactions, with the Sink Balancing Authority designated as the "manager" (the "Tag Authority").~~

~~The Functional Model recognizes this Interchange process as the current Industry practice and includes BA-to-BA "after hour" checkout for net Interchange between adjacent Balancing Authorities. Also, the Interchange Coordinator function "coordinates" and "communicates Interchange ("deals") that is ready for physical implementation between Balancing Authorities. The IC receives approvals that recognize ramping capability. The IC also communicates the individual Interchange information to all involved parties (Figure 6).~~



~~***Figure 6 — The Interchange Coordinator manages transactions between the source and sink Balancing Authorities.***~~

~~**Managing Bilateral Interchange Transactions — Allowable Concept**~~

~~The Functional Model does not prevent Balancing Authorities from scheduling Interchange with Interchange Coordinators. The ICs would ensure that the Arranged Interchange is balanced (equal and opposite) between the Source and Sink BAs. In the example in Figure 6, the IC manages a transaction from BA1 to BA4. The schedule is~~

~~BA1 → IA → BA4~~

~~and the transmission service path is~~

~~TSP1 → TSP2 → TSP3.~~

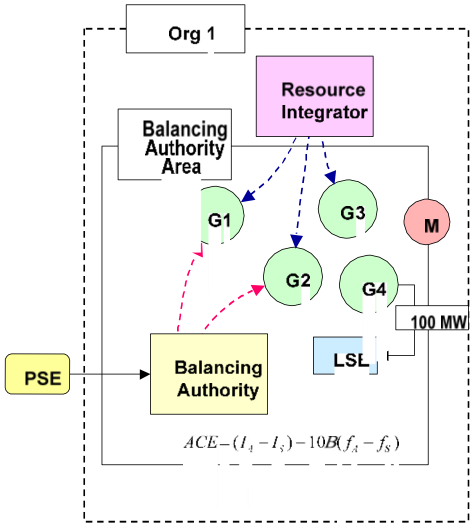


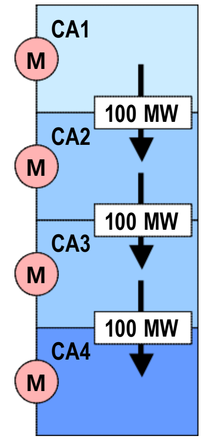
Figure 7 – The Purchasing-Selling Entity submits the bilateral transaction to the Balancing Authority for intra-BA transactions.

~~**Interchange Transactions within a Balancing Authority Area**. A bilateral Interchange within a Balancing Authority Area does not require Interchange Coordinator authorization. In the example in Figures 8 and 9, the Purchasing-Selling Entity submits the 100 MW request for Interchange to the Balancing Authority who will inform the Resource Integrator (or Market Operator) if the Resource Integrator needs to know which generators are committed to the Interchange, and to the Reliability Coordinator for reliability assessment.~~

~~The tables on the following page compare the Interchange checkout procedures that the Balancing Authorities use today with the procedures that the Balancing Authorities would use if this type of Interchange concept were applied.~~

Checkout under Existing NERC Practice Figure 8			
Control Area	**Actual from Tie Meters**	**Schedule with CA**	**Inadvertent**
CA1	+100 to CA2	+100 to CA2	0
CA2	-100 from CA1 +100 to CA3	-100 from CA1 +100 to CA3	0
CA3	-100 from CA2 +100 to CA4	-100 from CA2 +100 to CA4	0
CA4	-100 from CA3	-100 from CA3	0

Figure 8



Potential Future Checkout Figure 9			
Balancing Authority	**Actual from Tie Meters**	**Schedule with IC**	**Inadvertent**
BA1	+100 to BA2	+100 to IC	0
BA2	-100 from BA1 +100 to BA3	0	0
BA3	-100 from BA2 +100 to BA4	0	0
BA4	-100 from BA3	-100 from IC	0

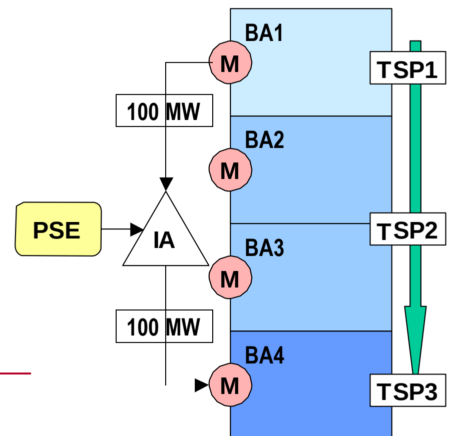


Figure 9

~~Part 7 - Managing Bilateral Interchange – Scheduling Agents~~

~~Some Transmission Providers provide a Scheduling Agent service for their Balancing Authority members. The Scheduling Agent provides a single point of contact for all Interchange into or out of those Balancing Authorities. For example, the Southwest Power Pool serves as a Scheduling Agent for its members, and any Balancing Authority external to SPP will schedule to any SPP Balancing Authority by way of the SPP as the Scheduling Agent. This simplifies Interchange scheduling for parties both internal and external to SPP.~~

~~In the example in Figure 10, two Interchange Coordinators arrange a total of 225 MW with the Scheduling Agent for a group of four Balancing Authorities as follows:~~

~~IS1 = 100 MW into BA1 IS3~~

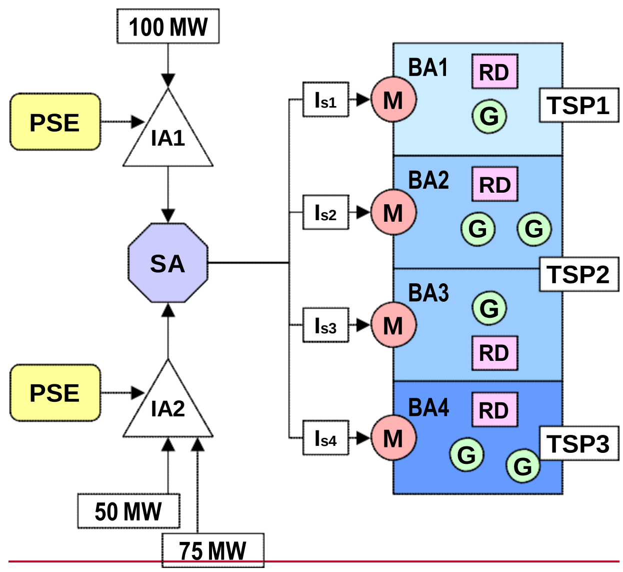
~~= 50 MW into BA3 IS4 = 75~~

~~MW into BA4 IS2 = 0~~

~~The Scheduling Agent must ensure that the sum of the Interchange from all Interchange Coordinators is exactly equal to the sum of the Interchange from the Scheduling Agent to its Balancing Authorities:~~

~~ISA1 + ISA2 = IS1 + IS2 + IS3 + IS4~~

~~Is1 + Is2 + Is3 + Is4 = 225 MW~~



~~Figure 10 - The Scheduling Agent divides a 100 MW transaction among a group of Balancing Authorities.~~

~~If the Balancing Authority(ies) use a Scheduling Agent, then the Interchange Coordinator will request approvals from the Scheduling Agent — not the Balancing Authority(ies) — during the Interchange authorization process. The Interchange Coordinator will also notify the Scheduling Agent of any Interchange curtailments.~~

~~Because Interchange scheduling is an integral function of the Balancing Authority, the Functional Model Working Group defines that the Scheduling Agent is actually an agent of the Balancing Authorities. The Balancing Authorities would still be the Responsible Entities for ensuring that the Interchange from the Scheduling Agent was incorporated into the BAs' energy management systems. Some have argued that the Scheduling Agent would need to be certified and monitored to ensure that it handled the Interchange properly.~~

~~Part 8 - Non-coincident Resource Integrator and Balancing Authority Areas~~

~~**Bilaterals between Market Areas.** In the examples above, each Balancing Authority Area was the same as the Market or Resource Integrator Area. When generation is dispatched (either cost-based or bid-based) over several Balancing Authority Areas, we may be faced with a bilateral Interchange whose source or sink is the entire Market Area, and cannot be identified with any particular Balancing Authority within that area. In this situation, the Interchange Coordinator interfaces with the Scheduling Agent for the Market Area. Then the Scheduling Agent, working with the Market Operator will determine how the bilateral Interchange is allocated among the Balancing Authority Areas.~~

~~As was explained in the technical discussion on reliability-related services, the Scheduling Agent ensures that the RDIS are properly allocated to the Balancing Authorities.~~

~~Now we can combine the Scheduling Agent's management of RDIS with bilateral Interchange Transactions as shown in Figure 11.~~

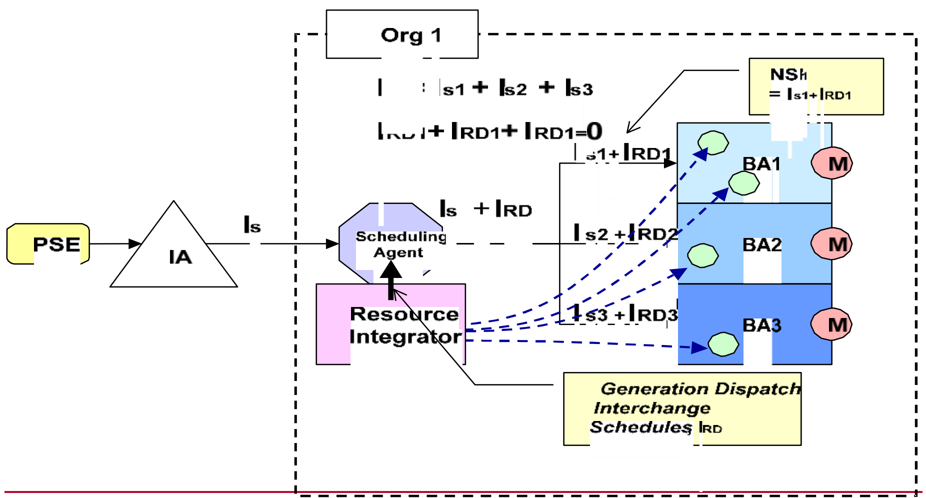
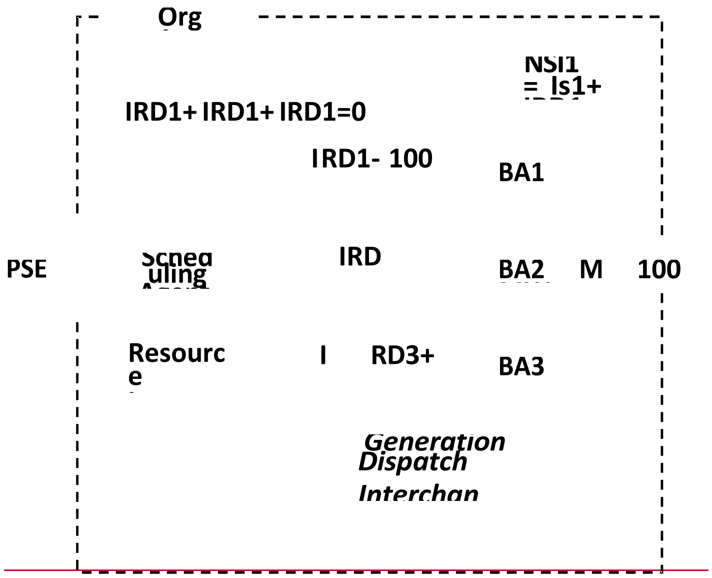


Figure 11 - The Scheduling Agent manages bilateral Interchange Transactions in to or out of the Market Area ~~as well as the Interchange Schedules that result from the~~ economic dispatch or market operations.

~~**Bilaterals between Balancing Authorities within the same Market Area**. Bilateral Interchange between two Balancing Authorities within the same Market Area does not require Interchange Coordinator management because the Market Area is under a common tariff, and the Market Operator would have a close relationship with the Reliability Coordinator. In the example in Figure 12 the Purchasing-Selling Entity has submitted a 100 MW request for Interchange from BA1 to BA3 directly to the Scheduling Agent, who would then coordinate the transaction between the source and sink Balancing Authorities. The Scheduling Agent then submits the resulting interchange schedule to the Source and Sink Balancing Authorities, and informs the Market Operator if the Market Operator needs to know which generators are committed to the transaction.~~



~~*Figure 12 - The PSE submits its Interchange Transaction information directly to the Scheduling Agent when the bilateral transaction is within the same Market Area.*~~

Part 3~~9~~ – Implementing Interchange Coordination

Requests for Interchange (RFI) are initiated by entities (Purchasing-Selling Entities, Load-Serving Entities, or Generator Owners) who have arranged for Interchange and contracted for Transmission Service from a Transmission Service Provider. The RFIs are submitted to a (Tag) agent service who confirms all information needed and electronically sends Tags to the authority service, or the Interchange Coordinator. The Interchange Coordinator ~~IC T~~tasks are ~~being~~ performed by the ~~organization~~ functional entities registered as Balancing Authorities (BAs), specifically the Sink Balancing Authority~~"sink BA"[8]~~ for a particular interchange transaction. A Sink Balancing Authority is defined as, "[the Balancing Authority in which the load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule."[9] ~~It has been noted that the Functional Model could in principle have assigned the IC Tasks to the BA and avoided the need for a separate Interchange function. This approach was not followed because it was envisioned in the future that the IC Tasks could be performed by entities other than a BA, a possibility that is allowed for by defining the IC separate from the BA. Therefore, the Functional Model *accommodates* the sink BA as the IC, but does not *require* it.~~

~~The implementation of the IC extends also to the NERC INT standards that exist today, which impose data collecting and interchange-information distribution requirements on an IC.~~

~~The NERC direction regarding registering of ICs is compatible with the approach taken in the Model:~~

- ~~There is a need for a separate Interchange Coordinator functional entity~~
- ~~Allowance is made for BAs to register as ICs, but organizations that are not BAs are not precluded from doing so.~~
- ~~The IC is an entity, not a software tool.~~

The remainder of this section clarifies the context and need for an Interchange Coordinator ~~from the perspective of the Model,~~ by describing the associated reliability tasks and their implications. ~~As such, it may be of use to those involved in registration processes.~~

INTERCHANGE PRACTICE

Background

To help ensure reliability, "requests" for ~~i~~Interchange ~~t~~Transactions (Arranged Interchange) must be approved before that request is allowed to become an ~~"i~~Implemented~~"~~ I~~i~~nterchange ~~transaction~~ (or Confirmed Interchange). Without approvals, it is possible that the sum of all ~~i~~Interchange ~~s~~Schedules in an interconnection will not sum to zero. That, in turn, would lead to the condition that even if every Balancing Authority were controlling to zero Area Control Error, there could still be off-generation occurring because of the Net Interchange ~~s~~Schedule being in error.

Historically, approvals were handled on a control area to control area basis. Net ~~i~~Interchange ~~s~~Schedules between neighbors were checked and approved prior to implementation. Only if there were disagreements did individual requests get checked. This pragmatic practice served the industry well — but not perfectly. When given control areas did not take the time to compute their own Net Schedule interchange (and instead merely accepted the numbers from its individual neighbors) — what can and did happen was that individual

~~8 That is, the BA in whose area the bilateral interchange transaction terminates.~~

9 Definition of Sink Balancing Authority from the NERC Glossary of Terms (as of Mary 15, 2016).

schedules were active on one side of the control area, but not on the other side. Not until serious operational symptoms arose (*e.g.*, unexplained parallel flows, or unusual number of time error corrections) was there an investigation.

Current Practice

The ~~Functional Model's~~ inclusion of an Interchange Coordinator in the Functional Model recognizes a reliability concern regarding responsibility for approving a ~~r~~Request for ~~i~~Interchange, and the distribution of the information for the approved request for ~~i~~Interchange. Each and every Interchange ~~t~~Transaction that a Purchasing-Selling Entity~~SE~~ desires to implement must have approvals from all parties involved, and must have approval by each of them regarding the characteristics of each of those Interchange ~~t~~Transactions.

Today, the approval and communication are implemented in a two-step process — each step focusing on different quantities. One step focuses on the individual Interchange ~~t~~Transactions and their respective characteristics. This step is carried out by a tagging authority, which is the Interchange Coordinator. In order to obtain approval or denial, the Interchange Coordinator sends the Request for Interchange electronically, as Arranged Interchange, to the (tag) approval service provider for the Balancing Authorities, Transmission Service Providers, Load-Serving Entities, Purchasing-Selling Entities, and Generator Owners. After obtaining approval or denial, the approval service then sends the decision to the Interchange Coordinator. If all parties approve the Interchange Transaction, the Arranged Interchange becomes Confirmed Interchange. The Interchange Coordinator then informs all parties of this status.

The other step focuses on implementing Net Interchange ~~s~~Schedules (*i.e.*, the net of the ~~t~~Transactions that were approved). This step is carried out by neighboring Balancing Authorities~~As~~. The Sink Balancing Authority is responsible for ensuring the process is properly carried out. ~~This two-step process can and does work. The problem is that when there is a breakdown in the process, there is no compliance process in place.~~

~~For example, if the tagging authority were the root cause of non-compliance (such as a computer error) that caused transaction information to elude analysis of a participant in the transaction, and that error resulted in a blackout, then no one would be held non-compliant, if no entity is registered as IC for the transaction. If a BA$_{left}$ accepts a Net Schedule from BA$_{center}$ but the transactions within that Net do not agree with the complementary transactions of the accepted Net Schedule between BA$_{center}$ and BA$_{right}$, then again no one can be held non-compliant if no one is registered as IC.~~

~~What is in place t~~Today ~~is~~ the NAESB ~~NERC~~ Tagging Specification is in place. ~~,~~ Under the NAESB Tagging Specification, ~~under which~~ each ~~s~~Sink Balancing Authority is responsible for providing ~~T~~tagging ~~S~~services, either directly or by arranging with a third party to provide this service as its agent.[10] ~~However, the Tagging Specification is not a standard and therefore not a sufficient basis for compliance enforcement.~~

~~An important question for many within industry is "how do you implement the concept of an Interchange Coordinator (IC)".~~

~~The initial step of the implementation requirements has been met with the NERC Board adoption of the Version 1 Interchange standards, which contain concepts and functions of the IA (now referred to as the IC). The Electronic Tagging Function Specification assigns the Tag Authority requirements to the entity responsible for Balancing Authority operations (*i.e.*, Sink BA).~~

[10] See, NAESB Electronic Tagging Functional Specification, version 1.8.0, approved November 7, 2007. Click here: http://reg.tsin.com/Tagging/e-tag/e-tag-spec-v-18-20071107.doc

~~To implement this concept, the Electronic Tagging Functional Specification (E-tag Spec.) was revised to map the Tagging Service requirement from the Balancing Authority to the entity performing the Interchange function for the Sink Balancing Authority's organization (still allows the Sink BA to use third party to fulfill the tasks of the requirements).~~

Part ~~10~~ 4 - ~~Distribution Provider as Load-Serving Entity~~ Risk-Based Registration

In support of its mission to assure the reliability of the Bulk Power System, NERC has transformed its approach to compliance and enforcement to be forward-looking with a focus on high reliability risk areas. The purpose of the NERC Risk-Based Registration (RBR) initiative was to ensure that the right entities are subject to the right set of applicable Reliability Standards, using a consistent approach to risk assessment and registration. In December 2014, NERC submitted a petition for approval of proposed revisions to the NERC Rules of Procedure (ROP), seeking to implement the changes sought as a result of the RBR initiative.[11] Specifically, NERC requested major reforms to the registration process, including the elimination of the Purchasing-Selling Entity (PSE), Interchange Authority (IA), and Load-Serving Entity (LSE) functional registration categories; modifications to the thresholds for registering entities as Distribution Providers (DP); and procedural improvements to the registration process. The procedural improvements to the registration process included: (1) the establishment of a materiality test for registration, with clear procedures and criteria for evaluation of whether an entity has a material impact on reliability with respect to above-the-line and below-the-line Registry Criteria determinations; (2) an enhanced process for review by a NERC-led, multi-regional panel of certain registration, deactivation and deregistration decisions, as well as certain requests for sub-set lists of Reliability Standards; (3) development of a common registration form to facilitate uniformity in Regional Entity collection of the information from registration candidates; and (4) one-time attestations that allow entities to record that a specific Reliability Standard requirement is "Not Applicable." On March 19, 2015, the Commission issued an order largely approving proposed revisions to the NERC ROP.[12]

As outlined in the RBR petition, the ERO compliance program and stakeholders benefit from the proposed revisions as they appropriately focus resources on entities with the greater potential impact on reliability. The RBR reforms were based on the February 2011 Commission technical conference in Docket No. AD11-6-000 on *Priorities for Addressing Risks to the Reliability of the Bulk-Power System*, where there was a recognition that "if everything is a priority, then nothing is a priority."[13] Priorities must be driven by a clear understanding of risks and consequences, and the costs and benefits associated with addressing them. With a shift toward risk-based approaches and a learning industry, NERC introduced quantitative measures of reliability performance. The revisions were a result of NERC taking a risk-based approach to reliability and to incorporating lessons-learned through continuously improving and adapting operations.

Even though the three entities (PSE, IA, and LSE) were removed from the NERC Registry Criteria, these entities–as users, owners and operators of the Bulk Power System–remain within in the statutory scope of both FERC and NERC pursuant to Section 215 of the Federal Power Act. Functionally, Load-Serving Entities, Purchasing-Selling Entities and Interchange Authorities continue to exist and continue to perform in the markets or operate under open access transmission tariffs, as applicable. The revisions did not alter the NERC registered ballot body (codified in Appendix 3D of the NERC Rules of Procedure).

~~FERC Order of October 16, 2008 approved a NERC filing that proposed, as a short-term solution, revisions to the NERC Statement of Compliance Registry Criteria (Registry Criteria) to provide that a distribution provider to~~

[11] See, Petition of the North American Electric Reliability Corporation for Approval of Risk-Based Registration Initiative Rules of Procedure Revisions, Docket No. RR15-4-000 (2014).

[12] North American Electric Reliability Corporation, 150 FERC ¶ 61,213 (2015).

[13] Additional information available on FERC website: http://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=5561&CalType=%20&CalendarID=116&Date=02/08/2011&View=Listview.

~~whose system the electric loads in retail choice areas are connected will be registered as the LSE for all loads connected to its system.~~[14]

~~The Order requires that "the Distribution Provider to whose system the electric loads in retail-choice areas are connected are to be registered as the LSE for all loads connected to its system for the purpose of compliance with NERC's approved reliability standards applicable to LSEs."~~

~~NERC states that, with respect to load served by retail choice through load aggregators, there may not be a clear agreement in place between the distribution providers and the load aggregators delineating the responsibilities between the parties regarding compliance with mandatory Reliability Standards. Further, the compliance filing explains that "NERC will exercise its discretion in the application of penalties or sanctions upon Distribution Providers who are providing this information on the behalf of loads served by a retail choice load aggregator until such time as both entities are either registered or the standards are updated to clarify the responsibilities for each party as ultimately identified in the longer-term solution proposed by NERC."~~

~~NERC stated that DPs have both the infrastructure and access to information to enable them to comply with the Reliability Standards that apply to LSEs. Moreover, distribution providers provide the wires over which the load of retail power marketers is served. NERC also pointed out that, with regard to distribution providers that provide wires service for retail power marketers, these DPs were LSEs for that load prior to state retail access programs. In many instances, these distribution providers remain providers of last resort and must plan their system taking into consideration all load served over their wires, including retail access load.~~

~~The Order also provides that a distribution provider will not be registered based on the above criterion if it has transferred responsibility to another entity (that is appropriately registered) by written agreement.~~

~~NERC also stated that this approach ensures that all loads are represented in the planning and operation of the Bulk-Power System by the entity with the best information regarding those loads.~~

~~The scope of the review leading to Version 5 of the Functional Model included consideration of whether changes should be made in the Model to accommodate these changes to the Registry Criteria.~~

~~Version 5 does *not* contain changes to reflect these changes to the Registry Criteria, as follows:~~

- ~~the problem and its solution relate to registration, not the Tasks performed, and as such do not directly affect the Model; this is in keeping with the approach used for the Joint Registration Organization, which is defined for compliance purposes and not in the Model~~
- ~~the present solution is a short-term one, with the longer-term solution yet to be defined.~~

~~[14] This section contains extracts from the order, which may be found at http://www.nerc.com/files/Statement_Compliance_Registry_Criteria-V5-0.pdf~~

~~Part 11 - Terminology Changes in Version 5~~

~~Version 5 contains terminology changes intended to improve consistency between the Model and the NERC Glossary, the Rules of Procedure (ROP) and Reliability Standards.[15] Inconsistency has potential for creating needless complexity, confusion and wasted effort for those who use NERC documents. The changes are of three types:~~

- ~~Entity terminology~~
- ~~Entity names~~
- ~~Entity definitions. Entity terminology~~

~~The term "responsible entity" in the Model has been changed to "functional entity".[16]~~

  - ~~The usage of "responsible" in Version 4 derived from an earlier version of the Model. Version 4 clarified that the Model is limited to describing the performance of tasks, but not compliance aspects such as responsibility for such performance. Version 5 takes this clarification one step further by replacing the term "responsible" in the Model.~~
  - ~~The Model uses the term functional entity to apply to a *class of entity*, such as a Balancing Authority, and makes no reference to the *specific organizations* that register as functional entities. Consistency within NERC documents would be improved if conforming changes were made to the NERC Rules of Procedure and Glossary of Terms to consistently use the term "functional entity" when the reference is to the *class of entity* (*e.g.*, BA), and use the terms "responsible entity" and "registered entity" when the reference is to a *specific organization* regarding its responsibility or registration, respectively.[17]~~

~~Entity names~~

- ~~The functional entity name Interchange Authority has been changed to Interchange Coordinator~~
  - ~~The term "coordinator" better reflects the nature of the function.~~
  - ~~A conforming change would be required in the Glossary (which also uses Interchange Authority)~~
- ~~Conforming changes would be required in other NERC documents.~~

~~Entity definitions~~

- ~~The Model has been revised to define the various functional entities, not the Functions as at present, consistent with the approach used in the Glossary and standards.~~
- ~~The functional entity definitions have been revised.~~
  - ~~The form of the definitions is uniform, with each definition beginning: "The functional entity ..."~~
  - ~~Each definition is single sentence, limited to a simple statement of the nature of the tasks performed. As a result some of the current descriptive wording in Version 4 or Glossary definitions has been removed in the Version 5 definitions.~~

~~[15] Full alignment will require conforming changes in Reliability Standards, the Glossary and ROP. These changes are seen as editorial that is, not representing changes to essential content.~~

~~[16] Version 4 actually uses "Responsible Entity". Because the Glossary and ROP generally use "responsible entity", *i.e.*, all lower case, this usage has been adopted for version 5 of the Model.~~

~~[17] These changes in terminology are intended to address confusion between the entity described in the Model and specific organizations, which has been a frequently expressed concern of stakeholders.~~

~~The following table gives the Version 4 definitions, the Glossary definitions (April 20, 2009), and the Version 5 definitions (recommended for use in the Glossary.~~

~~Functional Entity Definitions:~~

~~Model Version 4, NERC Glossary and Model Version 5~~

~~VERSION 4~~[18]	~~GLOSSARY~~[19]	~~VERSION 5~~[20]	~~COMMENT~~
~~Balancing Authority~~	**~~Balancing Authority~~**	**~~Balancing Authority~~**	
~~Integrates resource plans ahead of time, and maintains load-interchange- generation balance within a Balancing Authority Area and supports Interconnection frequency in real time.~~	~~The responsible entity that integrates resource ahead of time, maintains load- interchange-generation balance within a Balancing Authority Area, and supports Interconnection~~	~~The functional entity that integrates resource plans ahead of time, maintains generation-load-interchange-balance within a Balancing Authority Area, and contributes to Interconnection frequency~~	~~Minor Glossary change needed.~~
~~Compliance Enforcement Authority~~	**~~Compliance Monitor~~**	**~~Compliance Enforcement Authority~~**	
~~Monitors, reviews, and ensures compliance with Reliability Standards and administers sanctions or penalties for non-compliance to the standards.~~	~~The entity that monitors, reviews, and ensures compliance of responsible entities with reliability standards.~~	~~The functional entity that monitors, reviews, and ensures compliance with Reliability Standards and administers sanctions or penalties for non-~~	~~Glossary needs to be updated~~
~~Distribution Provider~~	**~~Distribution Provider~~**	**~~Distribution Provider~~**	

[18] ~~For simplicity of presentation, the definitions indicated for the Model in Version 4 are assigned to the functional entity, not the function. For example, the Model has a definition for the Standards Development function, but the definition is shown below as applying to the Standards Developer *functional entity*.~~

[19] ~~Glossary version of February 12, 2008. See link at http://www.nerc.com/files/Glossary_12Feb08.pdf~~

[20] ~~These definitions would replace existing definitions in the Glossary (but entities not currently defined in the Glossary would not be added).~~

~~VERSION 4~~	~~GLOSSARY~~	~~VERSION 5~~	~~COMMENT~~
~~Provides facilities that interconnect an End-use Customer load and the electric system for the transfer of electrical energy to the End-use Customer.~~	~~Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.~~	~~The functional entity that provides facilities that interconnect an End-use Customer load and the electric system for the transfer of electrical energy to the End-use Customer.~~	~~Glossary change needed – descriptive detail removed. Revised version would be essentially that of Version 4 of the Model.~~
~~Generator Operator~~	**~~Generator Operator~~**	**~~Generator Operator~~**	
~~Operates generating unit(s) to provide real and reactive power.~~	~~The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.~~	~~The functional entity that operates generating unit(s) and performs the functions of supplying energy and reliability-related services.~~	~~Minor Glossary change needed.~~
~~Generator Owner~~	**~~Generator Owner~~**	**~~Generator Owner~~**	
~~Owns and provides for maintenance of generating facilities.~~	~~Entity that owns and maintains generating units.~~	~~The functional entity that owns and maintains generating~~	~~Minor Glossary change needed.~~
~~Interchange Coordinator~~	**~~Interchange Authority~~**	**~~Interchange Coordinator~~**	
~~Ensures communication of Arranged Interchange for reliability evaluation purposes and coordinates implementation of valid and balanced Arranged Interchange between Balancing Authority Areas.~~	~~The 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.~~	~~The functional entity that ensures communication of Arranged Interchange for reliability evaluation purposes and coordinates implementation of valid and balanced Confirmed Interchange between Balancing Authority Areas.~~	~~Glossary changed needed. Revised version would be essentially that of Version 4 of the Model.~~
~~Load-Serving Entity~~	**~~Load-Serving Entity~~**	**~~Load-Serving Entity~~**	

~~Secures capacity, energy and transmission services (including necessary reliability-related services) to serve the End-use Customer.~~	~~Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of~~	~~The functional entity that secures energy and transmission services (and reliability-related services) to serve the electrical demand and energy~~	~~Minor Glossary change needed.~~

~~VERSION 4~~	~~GLOSSARY~~	~~VERSION 5~~	~~COMMENT~~
	~~its end-use customers.~~	~~requirements of its end-use customers.~~	
~~**Market Operator (Resource Integrator)**~~	~~[not defined]~~	~~**Market Operator (Resource Integrator)**~~	
~~The Market Operations function, its tasks, and the interrelationships with other entities are included in the Functional Model only as an interface point of reliability Functions with~~		~~The market entity whose interrelationships with other entities are included in the Functional Model only as an interface point of reliability functions with commercial functions.~~	~~Term not used in Reliability Standards and therefore is not required in the Glossary..~~
~~**Purchasing-Selling Entity**~~	~~**Purchasing-Selling Entity**~~	~~**Purchasing-Selling Entity**~~	
~~Purchases or sells energy, capacity, and necessary reliability-related services as required.~~	~~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.~~	~~The functional entity that purchases or sells, and takes title to, energy, capacity, and reliability- related services.~~	~~Glossary change needed – descriptive detail removed.~~
~~**Planning Coordinator**~~	~~**Planning Authority / Coordinator**~~	~~**Planning Coordinator**~~	
~~Ensures a plan (generally one year and beyond) is available for adequate resources and transmission within a Planning Coordinator area. It integrates and evaluates the plans from the Transmission Planners and Resource Planners within the Planning Coordinator area to ensure those plans~~	~~The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.~~	~~The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas~~	~~Minor Glossary changed needed.~~
~~**Reliability Assurer**~~	~~[not defined]~~	~~**Reliability Assurer**~~	

~~Monitors and evaluates the activities related to planning and operations, and coordinates activities of Responsible Entities to~~		~~The functional entity that monitors and evaluates the activities related to planning and operations, and coordinates activities of~~	~~Term not used in Reliability Standards and therefore is not required in the Glossary.~~

~~VERSION 4~~	~~GLOSSARY~~	~~VERSION 5~~	~~COMMENT~~
~~secure the reliability of the bulk power system within a Reliability Assurer Area and adjacent areas.~~		~~functional entities to secure the reliability of the Bulk Electric System within a Reliability Assurer Area and adjacent areas.~~	
~~Reliability Coordinator~~	**~~Reliability Coordinator~~**	**~~Reliability Coordinator~~**	
~~Ensures the real-time operating reliability of the bulk power system within a Reliability Coordinator Area.~~	~~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.~~	~~The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area.~~	~~Glossary changed – descriptive detail removed. Revised version would be essentially that of Version 4 of the Model.~~

~~Resource Planner~~	~~Resource Planner~~	~~Resource Planner~~	
~~Develops a plan (generally one year and beyond) within its portion of a Planning Coordinator area for the resource adequacy of its specific loads (End-use Customer demand and energy requirements) within a reliability area.~~	~~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.~~	~~The functional 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 Resource Planner area.~~	~~Minor Glossary change needed.~~
~~Standards Developer~~	~~[not defined]~~	~~Standards Developer~~	

~~VERSION 4~~	~~GLOSSARY~~	~~VERSION 5~~	~~COMMENT~~
~~Develops and maintains Reliability Standards to ensure the reliability of the bulk power system.~~		~~The functional entity that develops and maintains Reliability Standards to ensure the reliability of the Bulk Electric System.~~	~~Term not used in Reliability Standards and therefore is not required in the Glossary.~~
~~Transmission Operator~~	~~Transmission Operator~~	~~Transmission Operator~~	
~~Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.~~	~~The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.~~	~~The functional entity that ensures the Real-time operating reliability of the transmission assets within a Transmission Operator Area.~~	~~Glossary changed needed. Revised version would be essentially that of Version 4 of the Model.~~
~~Transmission Owner~~	~~Transmission Owner~~	~~Transmission Owner~~	
~~Owns and provides for the maintenance of transmission facilities.~~	~~The entity that owns and maintains transmission facilities.~~	~~The functional entity that owns and maintains transmission facilities.~~	~~Minor Glossary change needed.~~

~~Transmission Planner~~	~~Transmission Planner~~	~~Transmission Planner~~	
~~Develops a plan (generally one year and beyond) for the reliability of the interconnected bulk power system within the Transmission Planner Area. Ensures that the plan integrates resources and transmission within its area as well as coordinating with the plans from adjacent and overlapping Transmission Planners and Resource Planners. The Transmission Planner also ensures that the plan meets the Reliability Standards.~~	~~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.~~	~~The functional entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within a Transmission Planner Area.~~	~~Minor Glossary change needed.~~
~~Transmission Service Provider~~	~~Transmission Service Provider~~	~~Transmission Service Provider~~	
~~Administers the transmission tariff and provides transmission services under applicable transmission service agreements (for example, the pro forma tariff).~~	~~The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.~~	~~The functional entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.~~	~~Minor Glossary change needed.~~

Part 5~~12~~ - ~~Reliability~~ Areas and Boundaries

~~**Assets versus Geography as the Basis for Defining Areas and Boundaries**~~

~~It is useful for organizations that are functional entities to specify an associated Area, which defines the portion of the Bulk Electric System within which their functional entity status applies. Moreover, by reviewing all of the Areas for a particular functional entity, it is possible to establish whether there are overlapping responsibilities or gaps, which can then be eliminated. The concept of Areas and boundaries (the interfaces between adjacent Areas) is therefore important in establishing clear responsibilities for compliance with Reliability Standards.~~

The ~~Functional Model~~ building block for defining boundaries and ~~A~~areas for the functional entities that operate and plan the Bulk Electric System is electrical, namely the individual Bulk Electric System asset. That is, the building blocks are the individual ~~t~~Transmission, generation and customer equipment assets that collectively constitute the Bulk Electric System. This enables any given Bulk Electric System asset to be associated with at least one ~~single organization, with respect to any particular~~ functional entity. This will ~~therefore~~ provide the basis for clear assignment of responsibility for managing the potential reliability impacts of the asset.~~, where the specific responsibility is to be established in NERC's registration, certification and compliance processes.~~

~~It is noted that a~~ A geographic definition is not ~~adequate~~ appropriate in a situation where there are, for example, two Transmission Operators in a given geographic footprint, differentiated by the voltage level of the assets under their respective control. In such a situation, the use of the specific Bulk Electric System assets provides an adequate basis for defining Areas/boundaries.

The following areas and boundaries are essential for understanding how to reliably operate and plan for a particular BES asset:

1. **Reliability Coordinator Area**: The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.
2. **Balancing Authority Area**: The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.
3. **Transmission Operator Area**: The collection of Transmission assets over which the Transmission Operator is responsible for operating.
4. ~~1.~~4. **Transmission Planner area**: The collection of Transmission assets over which the Transmission Planner is responsible for planning.
5. ~~2.~~5. **Planning Coordinator area**: The collection of Transmission assets over which the Planning Coordinator is responsible for coordinating planning. Its area includes one or more Transmission Planner Areas.

~~NERC Rules of Procedure specify area relationships among functional entities, excerpted as follows:~~

~~2.2 Regional entities shall verify that all balancing authorities and transmission operators are under the responsibility of one and only one reliability coordinator.~~

~~2.3 Regional entities shall verify that all transmission elements of the bulk power system operated within their geographic boundaries are under the authority and control of one and only one transmission planner, planning authority, transmission owner, and transmission operator.~~

~~2.4 Regional entities shall verify that all loads and generation sources within their geographic boundaries are under the authority and control of one and only one balancing authority.~~

~~2.5 Regional entities shall verify that no geographical or electrical areas of the bulk power system within their boundaries have duplication of coverage or are lacking an entity to perform required duties and tasks as identified in the reliability standards.~~

~~Size Considerations Relating to Area~~

~~The Functional Model does not specify a minimum or maximum size for a reliability area. From the perspective of the Model, an organization qualifies to be the Responsible Entity for a particular Function by virtue of performing the Function's Tasks.~~

~~Size is not a consideration in the distinction between local-area versus wide-area reliability. Local-area reliability is the responsibility of the Transmission Operator in the sense of considerations relating to the Transmission Operator's local system or area, regardless of how large that area may be. Similarly, wide-area reliability is the responsibility of the Reliability Coordinator in the sense of considerations relating as well to the systems and areas of neighboring Reliability Coordinators, regardless of how small the Reliability Coordinator's own area may be.~~

~~Part 13 - Generating versus Transmission Assets~~

~~The Model does not attempt to define the boundary between generating and transmission facilities, in particular regarding facilities such as protective relays and lines that are within or in proximity to a generating plant perimeter. Such boundaries may be defined by NERC, Regional Entities or governmental authorities.~~

~~From the perspective of the Model, for a facility that is determined to be a generating facility, its owner will be a Generator Owner, and its operator a Generator Operator. Correspondingly, for a facility that is determined to be a transmission facility, its owner will be a Transmission Owner, and its operator a Transmission Operator.~~

~~It is recognized that an owner may not be the operator of its facility, as a result of delegating the operating of the facility to another party through an agreement, and that in all cases it is NERC's registration process, not the Model that determines assignment as a functional entity.~~

~~Part 14 - Roles in Load Curtailment~~

~~This section discusses the roles of the various functional entities that may be involved in load curtailment. These entities include: Reliability Coordinator, Balancing Authority, Transmission Operator, Distribution Provider and Load-Serving Entity.~~

~~Types of Load Curtailment~~

~~There are two general types of load curtailment — voluntary and non-voluntary.~~

~~A. Voluntary Load Curtailment~~

~~Voluntary load curtailments are usually arranged ahead of real time under some form of agreements — market price trigger, compensation, etc., or on a totally voluntary basis with or without any compensation. Implementation of voluntary load curtailment is intended to provide a relief to the market price in some established markets, or a relief to system demand to aid the Balancing Authority in a tight capacity/energy situation, or a relief to loading on a Distribution Provider system.~~

~~Voluntary load curtailment based on pricing structure need not be requested since it is governed by pre-arranged agreement and mechanism. Voluntary curtailments that have not been pre-arranged may need to be communicated. Since end-use customers are involved in the decision-making process and must respond to the request, and the Load-Serving Entity holds the contractual obligation to serve these customers, such requests are usually communicated to the end-use customers through the Load-Serving Entity as directed by the initiating entities, which include the Balancing Authority and the Distribution Provider, to address potential capacity/energy shortfall in the Balancing Authority area or potential overload on the Distribution Provider system.~~

~~B. Non-Voluntary Load Curtailment (Shedding)~~

~~Non-voluntary load curtailments are usually implemented in real time to address imminent or existing capacity/energy shortfalls or transmission reliability concerns such as exceedance of an IROL or SOL, or a low voltage problem. Some pre-arrangements may be made ahead of time such as identifying the amount and location of load to be shed, and specific critical loads that may be excluded from curtailment by feeder configuration. However, since implementation is often of urgent nature, a decision process involving the end-use customers and communication via the Load-Serving Entity is usually bypassed.~~

~~Depending on the need to implement this type of curtailment, load is either curtailed automatically (such as in the case of underfrequency or undervoltage load shedding), or a curtailment directive is made by the Reliability Coordinator, Balancing Authority, or Transmission Operator directly to the Distribution Provider for physical implementation (except when this can be accomplished directly by the Transmission Operator). The Distribution Provider may also have a need to curtail load to address overload problems on its system. In this case, the Distribution Provider may implement load shedding directly.~~

~~**Role of Responsible Entities in Load Curtailment Reliability**~~

~~**Coordinator**~~

~~The Reliability Coordinator maintains Real-time system reliability, which includes implementing a number of emergency actions which include directing load shedding to preserve system reliability. In addition, the Reliability Coordinator, in collaboration with the Balancing Authority and Transmission Operator, may also participate in invoking public appeals, voltage reductions, demand-side management, and even load shedding if the Balancing Authority cannot achieve resource-demand balance.~~

~~When a Reliability Coordinator has a need to direct non-voluntary load curtailment, it issues a directive to the Distribution Provider or the Transmission Operator to implement the curtailment.~~

~~**Balancing Authority**~~

~~When a Balancing Authority anticipates or experiences a capacity or energy shortfall, it will take actions such as public appeals, demand-side management programs, and load curtailment, as necessary to maintain a resource/demand/interchange balance. As time permits, the Balancing Authority may seek voluntary load curtailment to reduce demand in its area. In this case, the Balancing Authority will communicate such a request to the Load-Serving Entity. In the event of an Energy Emergency, the Balancing Authority may direct non-voluntary load curtailment by issuing a directive to the Distribution Provider or the Transmission Operator for implementation.~~

~~**Transmission Operator**~~

~~The Transmission Operator, in coordination with the Reliability Coordinator, can take actions such as implementing voltage reductions and implement load shedding to mitigate a transmission emergency. When a Transmission Operator sees a need for non-voluntary load curtailment to relieve transmission constraints, such as an actual or expected exceedance of an operating limit, it implements load shedding that is under its control, or directs a Distribution Provider to physically implement the curtailment.~~

~~**Distribution Provider**~~

~~The Distribution Provider provides the facilities that could be used to shed load for emergency action. It is that entity that has the capability to physically shed load, but it is generally not responsible for directing load shedding. Loading shedding is generally directed by the Reliability Coordinator, Balancing Authority and Transmission Operator.~~

~~However, the Distribution Provide may itself initiate voluntary and non-voluntary load curtailments for its own reasons, for example to reduce its area's demand or to mitigate overload on its system. When a Distribution Provider sees a need for voluntary load curtailment, it directs the Load-Serving Entity to communicate a request for curtailment to the end-use customers.~~

~~When it sees a need to implement non-voluntary load curtailment to address a loading or voltage concern, it implements the curtailment on its own.~~

~~**Load-Serving Entity**~~

~~The Load-Serving Entity identifies the loads for voluntary as well as non-voluntary curtailments. For voluntary load shedding, the LSE is responsible for making contractual arrangements with end-use customers who participate in such a program, and identifying to the Balancing Authorities and Distribution Providers of such arrangements so~~

~~that these customers, once committed, would be put on curtailment list if and when needed to address potential capacity shortage and/or system constraints.~~

~~For voluntary load curtailment that has not been pre-arranged, the Load-Serving Entity may be directed by the Balancing Authority or Distribution Provider to communicate its curtailment requests to the end-use customers.~~

~~For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons.~~

~~Once identified and necessary contractual arrangements are made, the Distribution Provider (or the Transmission Operator as appropriate) will make reasonable efforts to arrange (feeder) connection arrangement such that these critical loads will not be curtailed by the load shedding facilities until other options have been exhausted.~~

~~The Load-Serving Entity is responsible for communicating requests for voluntary curtailment to the appropriate end-use customers, thereby increasing the effectiveness of voluntary load curtailment. In some jurisdictions, it appears that the "wires" entity, *i.e.*, the Distribution Provider, that performs these Tasks. However, from a functional model viewpoint, it is the Load- Serving Entity function within that Distribution Provider organization that performs this task.~~

~~Part 15 - History of Revisions~~

~~Version 1~~

~~Version 1 of the Model was approved in February 2002.~~

~~Version 2~~

~~Version 2 of the Model was approved Feb. 10, 2004.[21]~~

~~Version 2 responded to confusion between a Function and the organization responsibility for its performance, by separately identifying the Responsible Entity associated with each Function. For example, whereas Version 1 used the single term Transmission Operator for both the Function and responsible entity, Version 2 introduced Transmission Operations as the Function (the Tasks), and Transmission Operator as the Responsible Entity for those Tasks. Corresponding changes were made for all Functions. This distinction has been maintained in subsequent versions.~~

~~The Market Operation Function and Market Operator were added to the Model to provide an interface point with commercial functions.~~

~~Version 1 contained only operating Functions. Version 2 introduced three planning Functions (Planning Reliability, Transmission Planning, Resource Planning) and three associated Responsible Entities (Planning Authority, Transmission Planner and Resource Planner).~~

~~Version 3~~

~~Version 3 of the Model was approved February 13, 2007.[22] It addressed a number of issues that arose as NERC transitioned to new, mandatory and enforceable reliability standards. Several of these issues were outlined in a final report issued by the Functional Model-Reliability Standards Coordination Task Force (FMRSCTF) in March 2005.[23] The FMRSCTF was established to ensure alignment between the Model and the new NERC standards being developed.~~

~~The changes introduced in Version 3 included:~~

- ~~The Reliability Authority entity name was changed to Reliability Coordinator, for consistency with terminology used in reliability standards.~~
- ~~Changes were made to more clearly define the Transmission Operations Tasks and the relationship of the Transmission Operator with the Reliability Coordinator~~
- ~~Changes were made to the Interchange Coordinator to accommodate the practice of Balancing Authority-to-Balancing Authority interchange scheduling~~
- ~~The Planning Authority was renamed the Planning Coordinator~~
- ~~The Regional Reliability Assurance Function and the Regional Reliability Organization Responsible Entity were added.~~
- ~~It was clarified that "area" of responsibility for a particular Responsible Entity's applied to the collection of Bulk Electric System assets associated with the entity, that is, that area was defined electrically, not~~

[21] ~~See ftp://www.nerc.com/pub/sys/all_updl/oc/fmrtg/Functional_Model_Version_2.pdf.~~

[22] ~~See ftp://www.nerc.com/pub/sys/all_updl/oc/fmrtg/Function_Model_Version3_Board_Approved_13Feb07.pdf.~~

[23] ~~Final Report of the Functional Model — Reliability Standards Coordination Task Force ("FMRSCTF"), approved March 11, 2005. See ftp://www.nerc.com/pub/sys/all_updl/sac/fmrsctf/FMRSC_TF_Report_3-11-05.pdf.~~

~~geographically.~~

~~Version 4~~

~~Version 4 included the following changes from Version 3:~~

- ~~The names Regional Reliability Assurance / Regional Reliability Organization were changed to Reliability Assurance / Reliability Assurer.~~

  ~~The name changes reflect the view that reliability assurance could be performed on other than a regional basis. Moreover, the functional entity need not be a Regional Entity.~~

- ~~The names Compliance Monitoring / Compliance Monitor were changed to Compliance Enforcement / Compliance Enforcement Authority.~~

  ~~The changes were judged to better reflect the strong role of compliance in the ERO regime.~~

- ~~The wording was changed in a number of instances to ensure that the Model's Tasks and relationships between Responsible Entities do not specify prescriptive requirements. Prescriptive requirements are specified in reliability standards and NERC processes, not in the Model.~~

- ~~For example, references in Version 2 that a Responsible Entity "must ensure" or "is required to ensure" were changed in Version 4 to simply "ensures".~~

- ~~It was clarified that the Generator Owner and Transmission Owner *provide for the maintenance* of their respective assets.~~

  ~~This recognizes that the performance of the maintenance may be assigned by the owner to another party, for example, to a Generator Operator or Transmission Operator, respectively.~~

~~Version 5~~

~~Version 5 introduces the following changes:~~

~~Entity name~~

- ~~Interchange Authority has been changed to Interchange Coordinator. Also incorporated are the terms Arranged and Confirmed Interchange to be consistent with terminology used in the INT standards.~~

~~Terminology~~

~~The term "responsible entity" in the Model has been changed to "functional entity".~~

- ~~The usage of "responsible" in Version 4 derived from an earlier version of the Model. Version 4 clarified that the Model is limited to describing the performance of tasks, but not compliance aspects such as responsibility for such performance. Version 5 takes this clarification one step further by replacing the term "responsible" in the Model.~~

- ~~The Model uses the term functional entity to apply to a *class of entity*, such as a Balancing Authority, and makes no reference to the *specific organizations* that register as functional entities.~~

- ~~Reliability is best served if there is consistency of definitions within all NERC documents. These documents include, but are not limited to, the Functional Model, the NERC Rules of Procedure and Glossary of Terms.~~

~~Entity definitions~~

- ~~The Model has been revised to define the various *functional entities*, not the *functions*, consistent with the approach used in the Glossary and standards.~~

- ~~The functional entity definitions have been revised.~~

- ~~The form of the definitions is uniform, with each definition beginning: "The functional entity that…"~~
- ~~Each definition is single sentence, limited to a simple statement of the nature of the tasks performed. As a result some of the current descriptive wording in Version 4 or Glossary definitions has been removed in the Version 5 definitions.~~

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Periodic Review Template: PER-003-1 Operating Personnel Credentials

December 2016

Introduction

The North American Electric Reliability Corporation (NERC) is required to conduct a periodic review of each NERC Reliability Standard at least once every ten (10) years, or once every five (5) years for Reliability Standards approved by the American National Standards Institute as an American National Standard.[1] The Reliability Standard identified above has been included in the current cycle of periodic reviews. The Review Team shall consist of two (2) subgroups; a Standing Review Team which is appointed annually by the Standards Committee for periodic reviews, and a stakeholder Subject Matter Expert (SME) team.[2] Consistent with Section 13 of the Standards Processes Manual, the Standards Committee may use a public nomination process to appoint the stakeholder SME team, or may use another method to appoint that results in a team that collectively has the necessary technical expertise and work process skills to meet the objectives of the project. The technical experts provide the subject matter expertise and guide the development of the technical aspects of the periodic review, assisted by technical writers, legal and compliance experts. The technical experts maintain authority over the technical details of the periodic review.
Together, the Standing Review Team and SME stakeholder team are the Review Team for a particular periodic review project and complete their portion of the template below.

The purpose of the template is to collect background information, pose questions to guide a comprehensive review of the Standard(s) by the Review Team, and document the Review Team's considerations and recommendations. The Review Team will post the completed template containing its recommendations for information and stakeholder input as required by Section 13 of the NERC Standard Processes Manual.

Review Team Composition

	Standing Review Team	Plus Section 13 (SMEs):
Non-CIP Standards	Chairs of the following NERC Standing Committees[3]: • Standards Committee (Also, the SC chair or his/her delegate from the	The Standards Committee will appoint stakeholder subject matter experts for the particular standard(s) being reviewed. The SMEs will work together with the

[1]NERC Standard Processes Manual 45 (2013), posted at http://www.nerc.com/pa/Stand/Documents/Appendix_3A_StandardsProcessesManual.pdf.
[2] Other reliability standards included as part of the Review Team's periodic review were PER-004-2 (included in a separate, concurrent, report) and PER-001-0.2 (which was approved for retirement on March 31, 2017 and therefore not included in either report).
[3]Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.

	SC will chair the Standing Review Team)[4] • Planning Committee • Operating Committee The Standing Review Team will meet with SMEs and help to ensure a consistent strategy and approach across all of the reviews.	Standing Review Team to conduct its review of the standard(s) and complete the template below.
CIP Standards	Chairs of the following NERC Standing Committees[5]: • Standards Committee (Also, the SC chair or his/her delegate from the SC will chair the Standing Review Team) • CIPC	The Standards Committee will appoint stakeholder subject matter experts for the particular standard(s) being reviewed. The SMEs will work together with the Standing Review Team to conduct its review of the standard(s) and complete the template below.

The Review Team will 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 from one of the following three (3) choices:

1. Recommend reaffirming the Standard as steady-state (Green); or
2. Recommend that the standard is sufficient to protect reliability and meet the reliability objective of the standard, however there may be future opportunity to improve a non-substantive or insignificant quality and content issue – i.e., continue to monitor (Yellow); or
3. Recommend that the standard needs revision or retirement (Red).

If the team recommends a revision to or a retirement of the Reliability Standard, it must also submit a Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision or retirement.

A completed Periodic Review Template and any associated documentation should be submitted by email to Darrel Richardson at darrel.richardson@nerc.net.

[4] The Standards Committee chair may delegate one member of the SC to chair one Standing Review Team's review of a standard s), and another SC member to chair a review of another standard(s).

[5] Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.

Applicable Reliability Standard: PER-003-1
Team Members (include name and organization): 1. Patti Metro, Nation Rural Electric Cooperative Association 2. Lauri Jones, Pacific Gas and Electric Company 3. Heather Morgan, EDP Renewables North America LLC 4. Jeffrey Sunvick, Western Area Power Administration 5. Jimmy Womack, Southwest Power Pool 6. Brad Perrett, Minnesota Power 7. Carolyn White Wilson, Duke Energy Corporation 8. Michael B. Hoke, PJM Interconnection LLC 9. Danny W. Johnson, Xcel Energy 10. Darrel Richardson, NERC Senior Standards Developer 11. Candice Castaneda, NERC Counsel 12. Michael Brytowski, Great River Energy PMOS Representative
Date Review Completed:

Background Information *(to be completed initially by NERC staff)*

1. Are there any outstanding Federal Energy Regulatory Commission (FERC) 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 (outstanding, in progress, or approved) Interpretation or Compliance Application Notice (CAN)? (*If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or other stakeholder-identified issue(s) that apply to the Reliability Standard*.)

   ☐ Yes

   ☒ No

   Please explain:

3. Is the Reliability Standard one of the most violated Reliability Standards?

☐ Yes

☒ No

If so, does the cause of the frequent violation appear to be a lack of clarity in the language?

☐ Yes

☐ No

Please explain:

Questions for the 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 your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above. Either as a guide to help answer the ensuing questions or as a final check, the Review Team is to use Attachment 3: Independent Expert Evaluation Process.

I. Quality

1. **Reliability Need, Paragraph 81:** Do any 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:** From the Background Information section of this template, has the Reliability Standard been the subject of an Interpretation, CAN or issue associated with it, or is frequently violated because of ambiguity?
   a. Does the Reliability Standard have obviously ambiguous language?
   b. Does the Reliability Standard have language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?
   d. Should the requirements stand alone as is, or should they be consolidated with other standards?
   e. Is the Reliability Standard complete and self-contained?
   f. Does the Reliability Standard use consistent terminology?

☒ Yes

☐ No

Please summarize your assessment: Although the response to the parent question above is "No" examination of its subparts (a) – (g) has led the Review Team to recommend a clarifying revision. The Project 2016-EPR-01 PER Review Team recommends that a clarifying footnote be added to PER-003-1 to ensure that stakeholders (now and in the future) understand (i) the connection between the Standard and the NERC System Operator Certification Program Manual; and (ii) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program.

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), Violation Severity Levels (VSL) and Time Horizons) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines?

☒ Yes

☐ No

If you answered "No," please identify which elements require revision, and why:

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 for coordination with other Reliability Standards?

☐ Yes

☒ No

If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

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?

   ☐ Yes

   ☒ No

   If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

7. **Practicable**:
   a. Can the Reliability Standard be practically implemented?

      ☒ Yes

      ☐ No

   b. Is there a concern that it is not cost effective as drafted?

      ☐ Yes

      ☒ No

   Please summarize your assessment of the practicability of the standard:

8. **Consideration of Generator and Transmission Interconnection Facilities:** Is responsibility for generator interconnection Facilities and Transmission Interconnection Facilities appropriately accounted for in the Reliability Standard? **N/A to this standard.**

   ☐ Yes

   ☐ No

   Guiding Questions:

   a. If the Reliability Standard is applicable to Generator Owners and/or Generator Operators, 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.)

   b. If the Reliability Standard is not applicable to Generator Owners and/or Generator Operators, is there a reliability-related need for treating generator Interconnection Facilities as Transmission Lines for the purposes of this Reliability Standard? (If so, Generator Owners that own and/or

Generator Operators that operate relevant generator Interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

c. If the Reliability Standard is applicable to Transmission Operators and/or Distribution Providers, is there any ambiguity about the inclusion of Transmission Interconnection Facilities? (If Transmission Interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

9. **Results Based Standard:** Is the Reliability Standard drafted as a results-based standard?

☒ Yes

☐ No

If not, please summarize your assessment:

Guiding Questions:

a. Does the Reliability Standard address performance, risk (prevention) and capability?

☒ Yes

☐ No

b. Does the Reliability Standard follow the RBS format (for example, Requirement and Part structure) in Attachment 1?

☐ Yes

☒ No

c. Does the Reliability Standard follow the Ten Benchmarks of an Excellent Reliability Standard[6]?

☒ Yes

☐ No

II. Content

[6] Ten Benchmarks of an Excellent Reliability Standard, posted at Page 626 of: http://www.nerc.com/pa/Stand/Resources/Documents/DT_Reference_Manual_Resource_Package_080114.pdf

10. **Technical accuracy:** Is the content of the Requirements technically correct, including identifying who does what and when?

☒ Yes

☐ No

If not, please summarize your assessment:

11. **Functional Model:** Are the correct functional entities assigned to perform the requirements, consistent with the Functional Model?

☒ Yes

☐ No

If not, please summarize your assessment:

12. **Applicability:** Is there a technical justification for revising the applicability of the Reliability Standard, or specific requirements within the standard, to account for differences in reliability risk?

☐ Yes

☒ No

If so, please summarize your assessment:

13. **Reliability Gaps:** Are the appropriate actions for which there should be accountability included, or is there a gap?

☐ Yes

☒ No

If a gap is identified, please explain:

14. **Technical Quality:** Does the Reliability Standard have a technical basis in engineering and operations?

☒ Yes

☐ No

If not, please summarize your assessment:

15. **Does the Reliability Standard reflect a higher solution than the lowest common denominator?**

☒ Yes

☐ No

If not, please summarize your assessment:

16. **Related Regional Reliability Standards**: Is there a related regional Reliability Standard, and is it appropriate to recommend the regional Reliability Standard be retired, appended into the continent-wide standard, or revised in favor of a continent-wide Standard?

☐ Yes

☒ No

If yes, please identify the regional standard(s) and summarize your assessment:

RED, YELLOW GREEN GRADING

Using the questions above, the Review Team shall come to a consensus on whether the Reliability Standard is Green – i.e., affirm as steady-state; Yellow –is sufficient to protect reliability and meet the reliability objective of the standard, however, there may be future opportunity to improve a non-substantive or insignificant quality and content issue – i.e., continue to monitor; or Red - either retire or needs revision, and, thus, a SAR should be developed to process the Standard through the Standards development process for retirement or revision. The reasons for the Review Team's conclusions of Green, Yellow, or Red shall be documented. If a consensus is not reached within the Review Team, minority reviews shall be posted for stakeholder comment, along with the majority opinion on whether the Reliability Standard is Green, Yellow or Red.

Recommendation

The answers to the questions above, along with its Red, Yellow, Green grading and the recommendation of the Review Team, will be posted for a 45-day comment period, and the comments publicly posted. The Review Team will review the comments to evaluate whether to modify its 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 *(This should be checked only if there are no outstanding directives, interpretations or issues identified by stakeholders.) GREEN*

☒ REVISE *(The standard is sufficient to protect reliability and meet the reliability objective of the standard, however there may be future opportunity to improve a non-substantive or insignificant quality and content issue.)* (Would include revision of associated RSAW.) *YELLOW*

☐ REVISE *(The recommended revisions are required to support reliability.)* (Would include revision of associated RSAW.) *RED*

☐ RETIRE (Would include revision of associated RSAW.) *RED*

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)*:

The Project 2016-EPR-01 PER Team recommends that a clarifying footnote be added to PER-003-1 to ensure that stakeholders (now and in the future) understand (i) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program; and (ii) the connection between the Standard and the Program Manual.

Preliminary Recommendation posted for industry comment (date):

Final Recommendation (to be completed by the Review Team after it has reviewed industry comments on the preliminary recommendation):

☐ REAFFIRM *(This should be checked only if there are no outstanding directives, interpretations or issues identified by stakeholders.) GREEN*

☐ REVISE *(The standard is sufficient to protect reliability and meet the reliability objective of the standard, however there may be future opportunity to improve a non-substantive or insignificant quality and content issue.)* (Would include revision of associated RSAW.) *YELLOW*

☐ REVISE *(The recommended revisions are required to support reliability.)* (Would include revision of associated RSAW.) *RED*

☐ RETIRE (Would include revision of associated RSAW.) *RED*

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR must be included and the technical justification included in the SAR)*:

Date submitted to Standards Committee:

Attachment 1: Results-Based Standards

Question 9 for the Review Team asks if the Reliability Standard is results-based. The information below will be used by the Review Team in making this determination.

Transitioning the current body of standards into a clear, concise, and effective body 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.[7] 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.

[7] 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.

Attachment 3: Independent Expert Evaluation Process

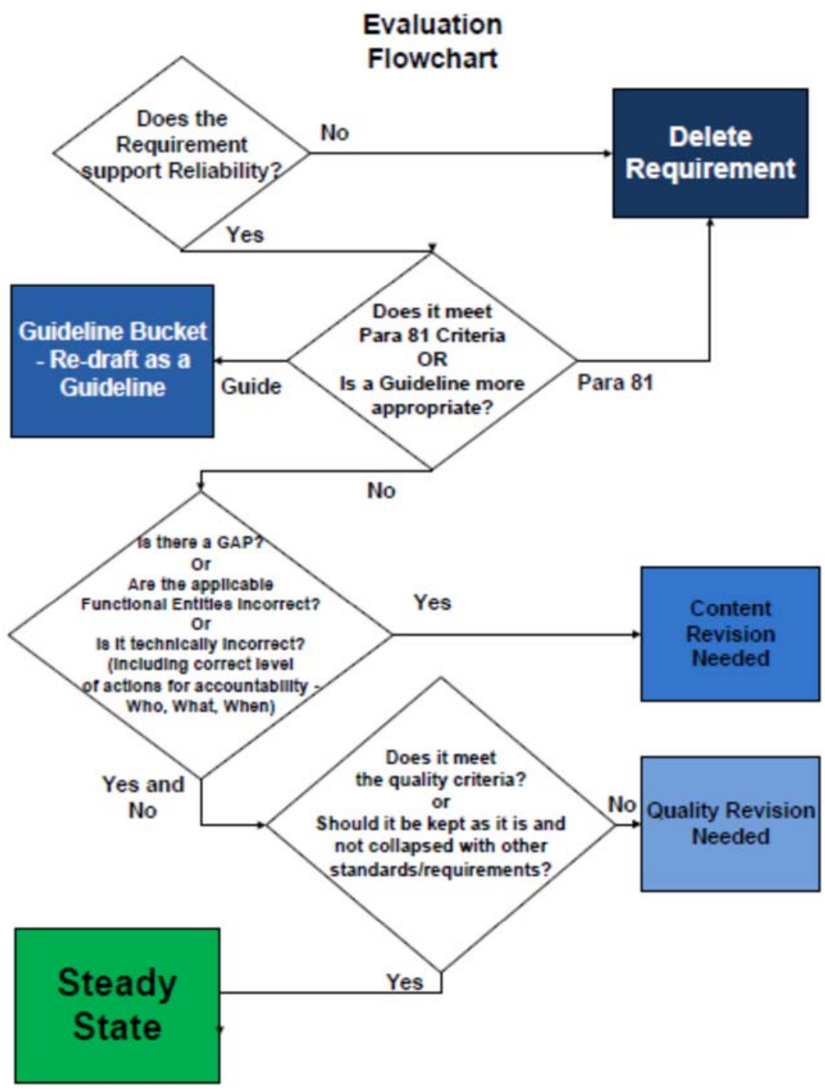


Figure 1: Evaluation Flow Chart

Periodic Review Template: PER-004-2 Reliability Coordination - Staffing

December 2016

Introduction

The North American Electric Reliability Corporation (NERC) is required to conduct a periodic review of each NERC Reliability Standard at least once every ten (10) years, or once every five (5) years for Reliability Standards approved by the American National Standards Institute as an American National Standard.[1] The Reliability Standard identified above has been included in the current cycle of periodic reviews. The Review Team shall consist of two (2) subgroups; a Standing Review Team which is appointed annually by the Standards Committee for periodic reviews, and a stakeholder Subject Matter Expert (SME) team.[2] Consistent with Section 13 of the Standards Processes Manual, the Standards Committee may use a public nomination process to appoint the stakeholder SME team, or may use another method to appoint that results in a team that collectively has the necessary technical expertise and work process skills to meet the objectives of the project. The technical experts provide the subject matter expertise and guide the development of the technical aspects of the periodic review, assisted by technical writers, legal and compliance experts. The technical experts maintain authority over the technical details of the periodic review.

Together, the Standing Review Team and SME stakeholder team are the Review Team for a particular periodic review project and complete their portion of the template below.

The purpose of the template is to collect background information, pose questions to guide a comprehensive review of the Standard(s) by the Review Team, and document the Review Team's considerations and recommendations. The Review Team will post the completed template containing its recommendations for information and stakeholder input as required by Section 13 of the NERC Standard Processes Manual.

Review Team Composition

	Standing Review Team	**Plus Section 13 (SMEs):**
Non-CIP Standards	Chairs of the following NERC Standing Committees[3]: • Standards Committee (Also, the SC chair or his/her delegate from the	The Standards Committee will appoint stakeholder subject matter experts for the particular standard(s) being reviewed. The SMEs will work together with the

[1]NERC Standard Processes Manual 45 (2013), posted at http://www.nerc.com/pa/Stand/Documents/Appendix_3A_StandardsProcessesManual.pdf.

[2] Other reliability standards included as part of the Review Team's periodic review were PER-003-1 (included in a separate, concurrent, report) and PER-001-0.2 (which was approved for retirement on March 31, 2017 and therefore not included in either report).

[3]Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.

	SC will chair the Standing Review Team)[4] • Planning Committee • Operating Committee The Standing Review Team will meet with SMEs and help to ensure a consistent strategy and approach across all of the reviews.	Standing Review Team to conduct its review of the standard(s) and complete the template below.
CIP Standards	Chairs of the following NERC Standing Committees[5]: • Standards Committee (Also, the SC chair or his/her delegate from the SC will chair the Standing Review Team) • CIPC	The Standards Committee will appoint stakeholder subject matter experts for the particular standard(s) being reviewed. The SMEs will work together with the Standing Review Team to conduct its review of the standard(s) and complete the template below.

The Review Team will 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 from one of the following three (3) choices:

1. Recommend reaffirming the Standard as steady-state (Green); or
2. Recommend that the standard is sufficient to protect reliability and meet the reliability objective of the standard, however there may be future opportunity to improve a non-substantive or insignificant quality and content issue – i.e., continue to monitor (Yellow); or
3. Recommend that the standard needs revision or retirement (Red).

If the team recommends a revision to or a retirement of the Reliability Standard, it must also submit a Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision or retirement.

A completed Periodic Review Template and any associated documentation should be submitted by email to Darrel Richardson at darrel.richardson@nerc.net.

[4] The Standards Committee chair may delegate one member of the SC to chair one Standing Review Team's review of a standard s), and another SC member to chair a review of another standard(s).

[5] Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.

Applicable Reliability Standard: PER-004-2
Team Members (include name and organization): 1. Patti Metro, Nation Rural Electric Cooperative Association 2. Lauri Jones, Pacific Gas and Electric Company 3. Heather Morgan, EDP Renewables North America LLC 4. Jeffrey Sunvick, Western Area Power Administration 5. Jimmy Womack, Southwest Power Pool 6. Brad Perrett, Minnesota Power 7. Carolyn White Wilson, Duke Energy Corporation 8. Michael B. Hoke, PJM Interconnection LLC 9. Danny W. Johnson, Xcel Energy 10. Darrel Richardson, NERC Senior Standards Developer 11. Candice Castaneda, NERC Counsel 12. Michael Brytowski, Great River Energy PMOS Representative
Date Review Completed:

Background Information ***(to be completed initially by NERC staff)***

1. Are there any outstanding Federal Energy Regulatory Commission (FERC) 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 (outstanding, in progress, or approved) Interpretation or Compliance Application Notice (CAN)? (*If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or other stakeholder-identified issue(s) that apply to the Reliability Standard*.)

   ☐ Yes

   ☒ No

   Please explain:

3. Is the Reliability Standard one of the most violated Reliability Standards?

☐ Yes

☒ No

If so, does the cause of the frequent violation appear to be a lack of clarity in the language?

☐ Yes

☐ No

Please explain:

Questions for the 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 your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above. Either as a guide to help answer the ensuing questions or as a final check, the Review Team is to use Attachment 3: Independent Expert Evaluation Process.

I. Quality

1. **Reliability Need, Paragraph 81:** Do any 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:

   This standard falls within Paragraph 81 Criterion B7, because all of its requirements are redundant with requirements in other FERC-approved reliability standards that are in effect or soon to be effective. It is not necessary or efficient to maintain such duplicative requirements and PER-004-2 may be retired with little to no effect on reliability. Specifically, PER-004-2's requirements are duplicated in standards:

   - PER-003-1, R1
   - PER-005-2, R2 and R3
   - IRO-002-4, R3 and R4
   - EOP-004-2, R2
   - IRO-008-2, R1, R2, and R4
   - IRO-009-2, R1 – R4

- IRO-010-2, R1 – R3
- IRO-014-3, generally
- IRO-018-1, R1-R3

Please refer to Page 10 of this document for a detailed justification for retirement of these requirements.

2. **Clarity:** From the Background Information section of this template, has the Reliability Standard been the subject of an Interpretation, CAN or issue associated with it, or is frequently violated because of ambiguity?
   a. Does the Reliability Standard have obviously ambiguous language?
   b. Does the Reliability Standard have language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?
   d. Should the requirements stand alone as is, or should they be consolidated with other standards?
   e. Is the Reliability Standard complete and self-contained?
   f. Does the Reliability Standard use consistent terminology?

☐ Yes

☒ No

Please summarize your assessment:

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), Violation Severity Levels (VSL) and Time Horizons) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines?

☒ Yes

☐ No

If you answered "No," please identify which elements require revision, and why:

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 for coordination with other Reliability Standards?

   ☐ Yes

   ☒ No

   If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

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?

   ☐ Yes

   ☒ No

   If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

7. **Practicable**:
   a. Can the Reliability Standard be practically implemented?

      ☒ Yes

      ☐ No

   b. Is there a concern that it is not cost effective as drafted?

      ☐ Yes

      ☒ No

   Please summarize your assessment of the practicability of the standard:

8. **Consideration of Generator and Transmission Interconnection Facilities:** Is responsibility for generator interconnection Facilities and Transmission Interconnection Facilities appropriately accounted for in the Reliability Standard? **Not Applicable.**

   ☐ Yes

   ☐ No

Guiding Questions:

a. If the Reliability Standard is applicable to Generator Owners and/or Generator Operators, 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.)

b. If the Reliability Standard is not applicable to Generator Owners and/or Generator Operators, is there a reliability-related need for treating generator Interconnection Facilities as Transmission Lines for the purposes of this Reliability Standard? (If so, Generator Owners that own and/or Generator Operators that operate relevant generator Interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

c. If the Reliability Standard is applicable to Transmission Operators and/or Distribution Providers, is there any ambiguity about the inclusion of Transmission Interconnection Facilities? (If Transmission Interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

9. **Results Based Standard:** Is the Reliability Standard drafted as a results-based standard?

☒ Yes

☐ No

If not, please summarize your assessment:

Guiding Questions:

a. Does the Reliability Standard address performance, risk (prevention) and capability?

☒ Yes

☐ No

b. Does the Reliability Standard follow the RBS format (for example, Requirement and Part structure) in Attachment 1?

☒ Yes

☐ No

c. Does the Reliability Standard follow the Ten Benchmarks of an Excellent Reliability Standard[6]?

☒ Yes

☐ No

II. Content

10. **Technical accuracy:** Is the content of the Requirements technically correct, including identifying who does what and when?

☒ Yes

☐ No

If not, please summarize your assessment:

11. **Functional Model:** Are the correct functional entities assigned to perform the requirements, consistent with the Functional Model?

☒ Yes

☐ No

If not, please summarize your assessment:

12. **Applicability:** Is there a technical justification for revising the applicability of the Reliability Standard, or specific requirements within the standard, to account for differences in reliability risk?

☐ Yes

☒ No

If so, please summarize your assessment:

13. **Reliability Gaps:** Are the appropriate actions for which there should be accountability included, or is there a gap?

[6] Ten Benchmarks of an Excellent Reliability Standard, posted at Page 626 of: http://www.nerc.com/pa/Stand/Resources/Documents/DT_Reference_Manual_Resource_Package_080114.pdf

☐ Yes

☒ No

If a gap is identified, please explain:

14. **Technical Quality:** Does the Reliability Standard have a technical basis in engineering and operations?

☒ Yes

☐ No

If not, please summarize your assessment:

15. **Does the Reliability Standard reflect a higher solution than the lowest common denominator?**

☒ Yes

☐ No

If not, please summarize your assessment:

16. **Related Regional Reliability Standards**: Is there a related regional Reliability Standard, and is it appropriate to recommend the regional Reliability Standard be retired, appended into the continent-wide standard, or revised in favor of a continent-wide Standard?

☐ Yes

☒ No

If yes, please identify the regional standard(s) and summarize your assessment:

RED, YELLOW GREEN GRADING

Using the questions above, the Review Team shall come to a consensus on whether the Reliability Standard is Green – i.e., affirm as steady-state; Yellow –is sufficient to protect reliability and meet the reliability objective of the standard, however, there may be future opportunity to improve a non-substantive or insignificant quality and content issue – i.e., continue to monitor; or Red - either retire or needs revision, and, thus, a SAR should be developed to process the Standard through the Standards development process for retirement or revision. The reasons for the Review Team's conclusions of Green, Yellow, or Red shall be documented. If a consensus is not reached within the Review Team, minority reviews shall be posted for stakeholder comment, along with the majority opinion on whether the Reliability Standard is Green, Yellow or Red.

Recommendation

The answers to the questions above, along with its Red, Yellow, Green grading and the recommendation of the Review Team, will be posted for a 45-day comment period, and the comments publicly posted. The Review Team will review the comments to evaluate whether to modify its 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 *(This should be checked only if there are no outstanding directives, interpretations or issues identified by stakeholders.) GREEN*

☐ REVISE *(The standard is sufficient to protect reliability and meet the reliability objective of the standard, however there may be future opportunity to improve a non-substantive or insignificant quality and content issue.)* (Would include revision of associated RSAW.) *YELLOW*

☐ REVISE *(The recommended revisions are required to support reliability.)* (Would include revision of associated RSAW.) *RED*

☒ RETIRE (Would include revision of associated RSAW.) *RED*

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)*:

PER-004-2 R1 is duplicative and all requirements are covered in other reliability standards. Specifically, PER-003-1 R1 states that each Reliability Coordinator shall staff its Real-time operating positions with System Operators who have obtained and maintained a valid NERC Reliability Operator certificate. PER-005-2 R1 states that each Reliability Coordinator shall design, develop and deliver training to its System Operators based on a list of Bulk Electric System (BES) company specific Real-time reliability-related tasks. Additionally, PER-005-2 R3 states that Reliability Coordinators have to verify that their personnel are capable of performing each of those tasks.

Moreover, in PER-004-2 R1, 24 hours per day, and seven days a week requirements are addressed by several NERC Reliability Standards and Requirements. These requirements cannot be accomplished without an entity having a 24/7 operation. IRO-002-4 R4 (enforceable 4/1/2017) requires that, "Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel…" In addition, IRO-002-4 R3 states that, "Each 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 within its Reliability Coordination Area." EOP-004-2 covers continuous observation through its reporting timeframes to meet OE-417 for Loss of Monitoring. Additional coverage is ensured through IRO 008-2 R2, "Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address …(SOL) and (IROL) exceedances…" and R4 states, "Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes." Reinforcing the structure of the 24 hours per day, and seven days per week requirement is carried out by IRO-010-2 R1, requiring that Reliability Coordinator's maintain documented specifications for the data to perform Operational Planning analyses, Real-time monitoring, and Real-time Assessments. Real-time is defined as, "Present time as opposed to future times," while Real-time Assessment is defined as "An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data." Using these definitions in the Reliability Standards further confirms that PER-004-2 Requirement 1 is duplicative and non-essential as its content is covered in multiple Reliability Standards.

PER-004-2 Requirement R2 is duplicated in numerous Reliability Standards justifying the need for retirement of this requirement. As described below, the Standards and requirements of IRO-002-4, IRO-008-2, IRO-009-2, IRO-010-2, IRO-014-3 and IRO-018-1 adequately ensure that protocols are in place to allow the Reliability Coordinator operating personnel to have the best available information at all times.

IRO-002-4, R3 states that the Reliability Coordinator shall monitor Facilities and work with neighboring Reliability Coordinator areas to identify SOL and IROL exceedances within its area. In order to ensure compliance with this Standard and Requirement, particular attention must be placed on SOLs, IROLs, and inter-tie facility limits.

IRO-008-2 ensures that the Reliability Coordinator performs analyses and assessments to prevent instability, uncontrolled separation, or cascading. R1, R2, and R4 of this Standard specifically require that an Operational Planning Analysis is performed to:

- assess whether the planned operations for the next-day will exceed SOLs and IROLs within its Wide Area,
- ensure that coordinated plans are developed for the next-day operations to address these exceedances, and
- execute Real-time Assessments at least once every 30 minutes.

To maintain compliance with the IRO-008-2 Standard, the Reliability Coordinator must place particular attention on SOLs and IROLs.

IRO-009-2 builds on IRO-008-2 by ensuring prompt action to prevent or mitigate instances where IROLs are exceeded. Through the Requirements of this Standard, assurances are made that the Reliability Coordinator has one or more Operating Processes, Procedures, or Plans that identify actions to take, or actions to direct others to take, to mitigate the magnitude and duration of an IROL exceedance identified in their Assessments.

IRO-010-2 provides data specifications that affords the Reliability Coordinator the specific data necessary to perform its Operational Planning Analyses, Real-time monitoring, Real-time Assessments and ensures that a protocol exists to resolve any data conflicts. This Standard ensures that the Reliability Coordinator has the best available information at all times to maintain compliance.

IRO-014-3 ensures that each Reliability Coordinator's operations are coordinated so that they will not adversely impact other Reliability Coordinator Areas and preserve the reliability benefits of interconnected operations. This Standard again builds on the coordination of the Operational Analyses and Real-time Assessments which requires the Reliability Coordinator to have the best available information at all times to maintain compliance.

IRO-018-1 established three requirements for Real-time monitoring and analysis capabilities to support reliable operations. Real-time monitoring involves observing operating status and operating values in Real-time to ensure awareness of system conditions. Through this Standard, processes and procedures are established for evaluating the quality of Real-time data and to provide assurance that any action taken addresses any data quality issues so that Real-time monitoring and Real-time Assessments performed by the Reliability Coordinator contains the best available information at all times.

Preliminary Recommendation posted for industry comment (date):

Final Recommendation (to be completed by the Review Team after it has reviewed industry comments on the preliminary recommendation):

☐ REAFFIRM *(This should be checked only if there are no outstanding directives, interpretations or issues identified by stakeholders.) GREEN*

☐ REVISE *(The standard is sufficient to protect reliability and meet the reliability objective of the standard, however there may be future opportunity to improve a non-substantive or insignificant quality and content issue.)* (Would include revision of associated RSAW.) *YELLOW*

☐ REVISE *(The recommended revisions are required to support reliability.)* (Would include revision of associated RSAW.) *RED*

☐ RETIRE (Would include revision of associated RSAW.) *RED*

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR must be included and the technical justification included in the SAR)*:

Date submitted to Standards Committee:

Attachment 1: Results-Based Standards

Question 9 for the Review Team asks if the Reliability Standard is results-based. The information below will be used by the Review Team in making this determination.

Transitioning the current body of standards into a clear, concise, and effective body 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.[7] 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.

[7] 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.

Attachment 3: Independent Expert Evaluation Process

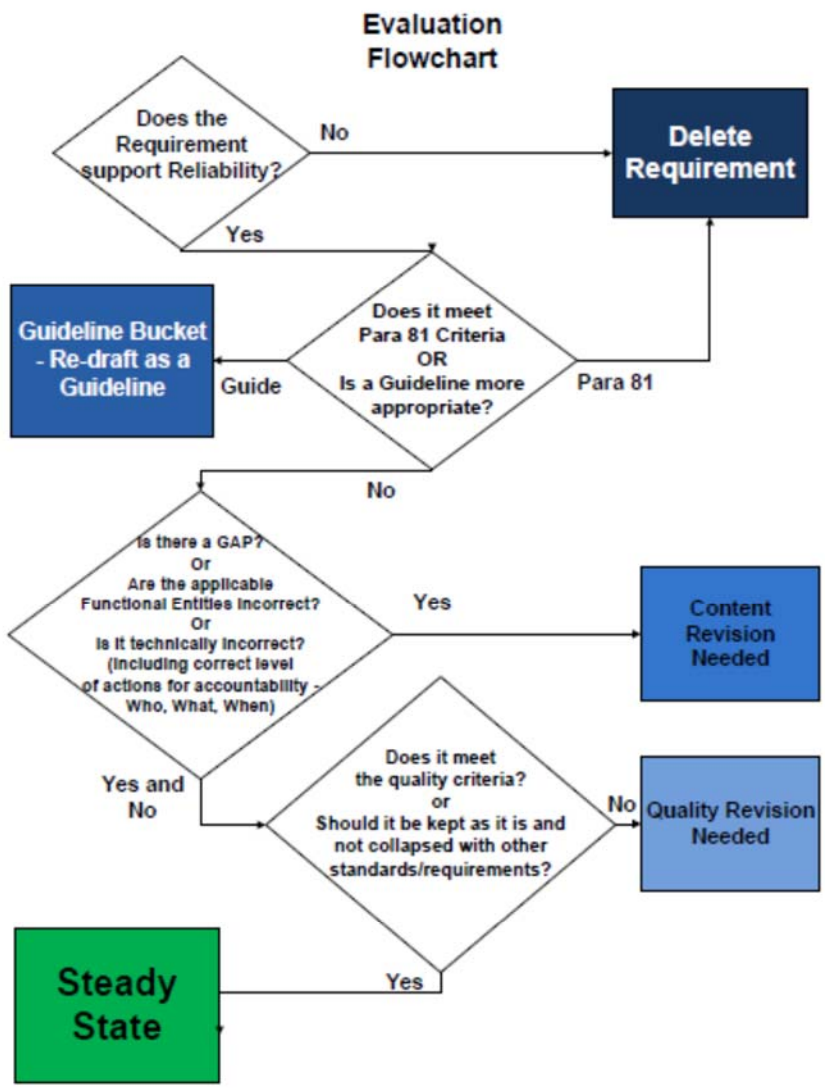


Figure 1: Evaluation Flow Chart

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%			
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%			

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
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%			
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%			

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
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%			
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%			

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
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%			
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%			

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
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		
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		

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
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%			
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%			

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
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		
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%			

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
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		
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%			

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
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		
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		

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
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		
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%			

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
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		
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%			

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
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
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		

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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

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
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%			
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%			

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
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%			
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%			

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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		
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		

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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	
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	

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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		
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 Meeting
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%/82.85%/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	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%	CIP-003 No CIP-004 Yes CIP-006 Yes CIP-007 Yes CIP-009 Yes			

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
483	Project 2014-02	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	Approval: 35.67%/80.76%/76.24%/78.41%/85.32%/49.42%/82.55%/78.58%	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% 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% Approval: 76.12%/74.23%/75.67%/85.49%/75.96%/78.67%/48.73%/78.87%/87.03%/93.34%/90.13%	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 9/18/14		
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		

RSC Meeting #17-1, Agenda Item 6.3: Comment History

(As of 1/31/2017)

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
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

RSC Meeting #17-1, Agenda Item 6.3: Comment History

(As of 1/31/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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	
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	

RSC Meeting #17-1, Agenda Item 6.3: Comment History

(As of 1/31/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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	
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

RSC Meeting #17-1, Agenda Item 6.3: Comment History

(As of 1/31/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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
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	

RSC Meeting #17-1, Agenda Item 6.3: Comment History

(As of 1/31/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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
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	

RSC Meeting #17-1, Agenda Item 6.3: Comment History

(As of 1/31/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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	
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

RSC Meeting #17-1, Agenda Item 6.3: Comment History

(As of 1/31/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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	
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

RSC Meeting #17-1, Agenda Item 6.3: Comment History

(As of 1/31/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
			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
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

RSC Meeting #17-1, Agenda Item 6.3: Comment History

(As of 1/31/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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
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

RSC Meeting #17-1, Agenda Item 6.3: Comment History

(As of 1/31/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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	
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	

RSC Meeting #17-1, Agenda Item 6.3: Comment History

(As of 1/31/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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
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

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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
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

<u>RSC Meeting #17-1, Agenda Item 6.3: Comment History</u>

(As of 1/31/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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
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

RSC Meeting #17-1, Agenda Item 6.3: Comment History

(As of 1/31/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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
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

RSC Meeting #17-1, Agenda Item 6.3: Comment History

(As of 1/31/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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
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

RSC Meeting #17-1, Agenda Item 6.3: Comment History

(As of 1/31/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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
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

RSC Meeting #17-1, Agenda Item 6.3: Comment History

(As of 1/31/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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
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		Informal		7/21/14	Yes 7/21/14

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		Development Plan					
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 for BAL-005 and BAL-006	BAL-005 BAL-006	Informal	07/16/14	08/14/14	Yes 8/12/14
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

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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 CIP-007-X CIP-010-X CIP-011-X	Formal	09/03/14	10/17/14	Yes 10/17/14
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	PRC-001-1.1 PRC-019-2	Formal	11/05/14	12/23/14	Yes 12/22/14

RSC Meeting #17-1, Agenda Item 6.3: Comment History

(As of 1/31/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		for Dispersed Generation Resources	PRC-024-1				
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
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-010-2	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
261	Project 2015-04	Project 2015-04 Alignment of Terms	SAR	Formal	2/24/15	4/13/15	Yes 4/13/15
262	Project 2007-17.4	Project 2007-17.4 PRC-005 Order No. 803 Directives	SAR	Informal	3/12/15	4/10/15	Yes 4/13/15
263	Project 2015-06	Project 2015-06 Interconnection Reliability Operations and Coordination	SAR	Informal	3/16/15	4//15/15	Yes 4/15/15
264	Project 2010-14.2.2	Project 2010-14.2.2 Phase 2 of Balancing Authority Reliability-based Controls: Time Error Correction	SAR	Informal	3/17/15	4//15/15	Yes 4/15/15

RSC Meeting #17-1, Agenda Item 6.3: Comment History

(As of 1/31/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
265	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-008-1	Informal	3/27/15	5/11/15	Yes 5/11/15
266	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-006-2	Informal	3/27/15	5/11/15	Yes 5/11/15
267	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-005-2	Informal	3/27/15	5/11/15	Yes 5/11/15
268	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-004-2	Informal	3/27/15	5/11/15	Yes 5/11/15
269	Project 2007-06	Project 2007-06 System Protection Coordination PRC-027-1 (Draft 5)	PRC-027-1	Formal	4/1/15	5/15/15	Yes 5/15/15
270	Project 2010-04.1	Project 2010-04.1 MOD-031 FERC Order No. 804 Directives	SAR	Informal	4/16/15	5/19/15	Yes 5/19/15
271	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems – RAS	PRC-012-2	Informal	4/30/15	5/20/15	Yes 5/20/15
272	Project 2015-03	Project 2015-03 Periodic Review of System Operating Limit Standards	FAC-010-3 FAC-011-3 FAC-014-2	Formal	5/4/15	6/17/15	Yes 6/17/15
273	Project 2015-06	Project 2015-06 Interconnection Reliability Operations and Coordination	IRO-006-East-2 IRO-009-2	Formal	5/21/15	7/8/15	Yes 7/8/15
274	Project 2007-17.4	Project 2007-17.4 PRC-005 FERC Order No. 803 Directive	PRC-005-3	Formal	6/11/15	7/10/15	Yes 7/10/15
275	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generations Resources	PRC-004-2.1 PRC-005-2 PRC-005-3	Informal	6/12/15	7/13/15	Yes 7/13/15
276	Project 2015-07	Project 2015-07 Internal Communications Capabilities	COM-001-2	Informal	6/11/15	7/15/15	Yes 7/15/15
277	Project 2015-04	Alignment of Terms	Glossary Terms	Formal	6/12/15	7/23/15	Yes 7/23/15
278	Project 2009-02	Real-time Monitoring and Analysis Capabilities	SAR	Formal	7/16/15	8/17/15	Yes 8/17/15
279	NERC 2016-2018	Reliability Standards Development Plan	Development Plan	Formal	7/16/15	8/17/15	Yes 8/17/15
280	Project 2015-08	Emergency Operations	EOP-004-2 EOP-005-2 EOP-006-2 EOP-008-1	Informal	7/21/15	8/19/15	Yes 8/19/15
281	Project 2010-14.1	Phase 1 of Balancing Authority Reliability-	BAL-002-2	Formal	7/7/15	8/20/15	Yes 8/20/15

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		based Controls					
282	Project 2010-14.2.2	Phase 2 of Balancing Authority Reliability-based Controls: Time Error Correction	BAL-004-0	Survey	8/12/15	8/25/15	Yes 8/25/15
283	Project 2007-06.2	Phase 2 of System Protection Coordination	TOP-009-1	Formal	7/29/15	9/11/15	Yes 9/11/15
284	Project 2007-06	System Protection Coordination	PRC-027-1	Formal	7/29/15	9/11/15	Yes 9/11/15
285	Project 2010-14.2.1	Phase 2 of Balancing Authority Reliability-based Controls	BAL-005-1 BAL-006-3	Formal	7/30/15	9/14/15	Yes 9/14/15
286	Project 2007-17.4	PRC-005 FERC Order No. 803 Directive	PRC-005-6	Formal	7/30/15	9/16/15	Yes 9/16/15
287	Project 2010-04.1	MOD-031 FERC Order No. 804 Directives	MOD-031-2	Formal	7/31/15	9/18/15	Yes 9/18/15
288	Project 2015-09	Establish and Communicate System Operating Limits	FAC-010-3 FAC-011-3 FAC-014-2	Informal	8/20/15	9/21/15	Yes 9/21/15
289	Project 2010-07.1	Vegetation Management	FAC-003-3	Informal	8/24/15	9/28/15	Yes 9/28/15
290	Project 2010-05.3	Phase 3 of Protection Systems: Remedial Action Schemes	PRC-012-2	Formal	8/20/15	10/5/15	Yes 10/5/15
291	Project 2009-02	Real-time Reliability Monitoring and Analysis Capabilities	IRO-018-1 TOP-010-1	Formal	9/24/15	11/9/15	Yes 11/9/15
292	Project 2010-14.2.2	Phase 2 of Balancing Authority Reliability-based Controls	BAL-004-0	Formal	9/24/15	11/12/15	Yes 11/12/15
293	Project 2015-07	Internal Communications Capabilities	COM-001-3	Formal	9/25/15	11/16/15	Yes 11/16/15
294	Project 2007-06.2	Phase 2 of System Protection Coordination	TOP-009-1	Formal	10/6/15	11/19/15	Yes 11/19/15
295	Project 2010-07.1	Vegetation Management	FAC-003-3	Formal	10/30/15	12/16/15	Yes 12/16/15
296	Project 2015-10	Single Points of Failure SAR	TPL-001	Informal	11/12/15	12/17/15	Yes 12/17/15
297	Project 2010-05.3	Phase 3 of Protection Systems RAS	PRC-012-2	Formal	11/25/15	1/8/16	Yes 1/8/16
298	Project 2010-14.2.1	Phase 2 of Balancing Authority Reliability-based Controls	BAL-005-1 FAC-001-3 BAL-006-2	Formal	12/31/15	1/11/16	Yes 1/11/16
299	Project 2009-02	Real-time Reliability Monitoring and Analysis Capabilities	IRO-018-1 TOP-010-1	Formal	12/10/15	1/25/16	Yes 1/25/16
300	Project 2016-01	Modifications to TOP and IRO Standards	SAR	Informal	1/22/16	2/22/16	Yes 2/22/16
301	Project 2010-05.3	Phase 3 of Protection Systems RAS	PRC-012-2	Formal	2/3/16	3/18/16	Yes 3/18/16
302	Project	Modifications to CIP	SAR	Informal	3/23/16	4/21/16	Yes

RSC Meeting #17-1, Agenda Item 6.3: Comment History

(As of 1/31/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
	2016-02	Standards					4/21/16
303	Project 2007-06.2	Phase 2 of System Protection Coordination	PER-006-1 & Two Definitions	Formal	3/10/16	4/25/16	Yes 4/25/16
304	Project 2015-07	Internal Communications Capabilities	COM-001-3	Formal	3/23/16	5/9/16	Yes 5/6/16
305	CEP	Cost Effectiveness Pilot	TPL-001-4	Informal	4/27/16	5/26/16	Yes 5/26/16
306	Project 2013-03	Geomagnetic Disturbance Mitigation Revised White Papers	SAR	Informal	5/12/16	6/13/16	Yes 6/13/16
307	Project 2015-10	Single Points of Failure	SAR	Informal	5/26/16	6/24/16	Yes 6/24/16
308	Project 2016-02	Modifications to CIP Standards	SAR	Informal	6/1/16	6/30/16	Yes 6/30/16
309	Draft 2017-2019	Reliability Standards Development Plan	RSDP	Informal	6/20/16	7/19/16	Yes 7/19/16
310	EPR	Enhanced Periodic Review Standing Review Team	Standards Grading	Informal	6/30/16	8/1/16	Yes 8/1/16
311	Project 2016-01	Modifications to TOP and IRO Standards	IRO-002-5 TOP-001-4	Formal	6/20/16	8/3/16	Yes 8/3/16
312	Project 2015-09	Establish and Communicate System Operating Limits	FAC-014-3	Formal	7/14/16	8/12/16	Yes 8/12/16
313	Project 2015-09	Establish and Communicate System Operating Limits	FAC-011-4	Formal	7/14/16	8/12/16	Yes 8/12/16
314	Project 2015-08	Emergency Operations	EOP-005-3 EOP-006-3 EOP-008-2	Formal	6/30/16	8/15/16	Yes 8/15/16
315	Project 2016-02	Modifications to CIP Standards	CIP-003-7	Formal	7/21/16	9/6/16	Yes 9/6/16
316	FMAG	Functional Model Advisory Group	Reliability Functional Model and Technical Document	Informal	7/21/16	9/7/16	Yes 9/7/16
317	Project 2015-08	Emergency Operations	EOP-004-4	Formal	7/25/16	9/8/16	Yes 9/8/16
318	Project 2015-INT-01	Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec)	CIP-002-5.1	Formal	7/27/16	9/12/16	Yes 9/12/16
319	Project 2016-01	Modifications to TOP and IRO Standards SAR	TOP-001-3 IRO-002-4	Formal	8/31/16	10/17/16	Yes 10/14/16
320	Project 2016-04	Modifications to PRC-025-1 SAR	PRC-025-1	Formal	9/16/16	10/18/16	Yes 10/18/16
321	Project 2016-03	Cyber Security Supply Chain Management	SAR	Informal	10/20/16	11/18/16	Yes 11/18/16
322	Project	Modifications of CIP	CIP-003-TCA	Informal	11/1/16	11/18/16	Yes

RSC Meeting #17-1, Agenda Item 6.3: Comment History

(As of 1/31/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
	2016-02	Standards					11/18/16
323	Project 2016-02	Modifications of CIP Standards	CIP-003-7	Formal	11/23/16	12/5/16	Yes 12/5/16
324	Project 2015-08	Emergency Operations	EOP-005-3 EOP-006-3	Formal	10/26/16	12/9/16	Yes 12/9/16
325	Project 2015-08	Emergency Operations	EOP-004-4	Formal	11/18/16	1/6/17	Yes 1/6/17
326	Project 2013-03	Geomagnetic Disturbance Mitigation	SAR	Informal	12/16/16	1/20/17	Yes 1/20/17
327	Project 2016-02	Modifications of CIP Standards	CIP-003-7(i)	Formal	12/12/16	1/25/17	Yes 1/25/17
328	Project 2016-EPR-01	Enhanced Periodic Review of Personnel Performance, Training and Qualifications Standard (PER)	PER-001-0.2 PER-003-1 PER-004-2	Formal	1/10/17	2/23/17	Yes 2/23/17

Note: RSC past comment forms are posted on the NPCC Website under "Standards - Regional Standards Comments."

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 NERC's PRC-006-1/PRC-006-2 Automatic Underfrequency Load Shedding and PRC-024-1/PRC-024-2 Generator Frequency and Voltage Protective Relay Settings standards.

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.

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/PRC-006-2, of not meeting the program performance characteristics as identified in Requirement R3 of PRC-006-1/PRC-006-2.

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.

Retiring PRC-006-NPCC-1 is to be considered if it is determined that it can be retired without sacrificing the ability to develop an effective underfrequency load shedding program.

Industry Need (Provide a detailed statement justifying the need for the proposed standard, along with any supporting documentation**.)**

To enhance efficiencies and cost effectiveness, it must be determined if PRC-006-NPCC-1 requirements can be revised or retired to address the new NERC BES definition, Paragraph 81, and eliminate redundancy leading to double jeopardy with PRC-006-1/PRC-006-2 and PRC-024-1/PRC-024-2 requirements without sacrificing the ability to develop an effective underfrequency load shedding program.

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 the new NERC BES definition, and Paragraph 81. In addition, PRC-006-NPCC-1 will be reviewed against NERC's PRC-006-1/PRC-006-2 and PRC-024-1/PRC-024-2 2-2. PRC-006-1/PRC-006-2 mandates the establishment of design and documentation requirements for automatic underfrequency load shedding (UFLS) programs. PRC-024-1/PRC-024-2 mandate that Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions. These "umbrellas" encompasses the relevant requirements in PRC-006-NPCC-1. However, the relevant requirements in each of the standards are to be compared and the requirements of PRC-006-NPCC-1, if so determined, are revised or deleted to eliminate redundancy and the concomitant double jeopardy. The review will also ensure that NERC Rules of Procedure, Section 312. Regional Reliability Standards, bullet 1that 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.” will govern.

PRC-006-1/PRC-006-2 specifies 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/PRC-006-2.

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.

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 (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 Quebec Interconnection (2) 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. Review the need to include the performance criteria presently in Directory#12 into PRC-006-NPCC-02, or whether the performance criteria included in PRC-006-1/PRC-006-2 is sufficient.

Interpretations of PRC-006-NPCC-1 to be considered to clarify PRC-006-NPCC-2.

The review will include an assessment of the need to include language to address dispersed generation resources.

PRC-006-NPCC-2 should be made to conform to the NERC Results Based Standard format.

After this review is completed, it will be determined if PRC-006-NPCC-1 should be revised, or retired.

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/PRC-006-2 and PRC-024-1/PRC-024-2 to determine if revisions are necessary, or retirement of PRC-006-NPCC-01 possible. Determine the necessity for including wording to address dispersed generation resources. Consider incorporating more stringent aspects of Directory#12 in order to facilitate future retirement of Directory#12.

Related Standards

Standard No.	**Explanation**
PRC-006-1/PRC-006-2	NERC Automatic Underfrequency Load shedding
PRC-024-1/PRC-024-2	NERC Generator Frequency and Voltage Protective Relay Settings

Related SARs or RSARs

SAR ID	**Explanation**

NPCC, Inc.

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

PRC-006-NPCC-02 Automatic Underfrequency Load Shedding

AGENDA FOR MEETING #4
January 12, 2016 9:00 a.m. – 4:00 p.m. EST
NPCC Office
1040 Avenue of Americas 10th Floor
New York, NY
Attire: Business Casual

Dial-In: 415-655-0003 (USA) / 416-915-6530 (Canada) **Guest Code: 643789801**
Password: aPtPA?83 (27872083 from phones)

Attendees:

	Name	Organization	Comment
1.	Guy Zito	Northeast Power Coordinating Council	In Person
2.	Ruida Shu	Northeast Power Coordinating Council	In Person
3.	Gerry Dunbar	Northeast Power Coordinating Council	In Person
4.	Daniel Kidney	Northeast Power Coordinating Council	In Person
5.	Juan Villar	FERC	In Person
6.	Vincent Morissette	Hydro Québec TransÉnergie	In Person
7.	Dean Latulipe	National Grid	In Person
8.	Dan Taft	Con Edison	In Person
9.	Tim Kucey	PSEG Fossil	In Person
10.	Brian Robinson	Utility Services	In Person
11.	Jessica Lau	Orange and Rockland	In Person
12.	Ben Wu	Orange and Rockland	Via Phone
13.	Jeannette Gauthier	Hydro Québec TransÉnergie	Via Phone
14.	Nick Paratta	PLM	Via Phone
15.	John Pearson	ISO-NE	Via Phone
16.	David Gordon	MMWEC	Via Phone
17.	David Ramkalawan	OPG	Via Phone
18.	Constantin Chitescu	OPG	Via Phone
19.	Hamid Hamadani	Hydro One	Via Phone
20.	John McLaughlin	Eversource	Via Phone
21.	Sean Bodkin	Dominion	Via Phone
22.	Dennis Fuentes	FERC	Via Phone

Introductions and Chair's Remarks

Dan Taft called the meeting in order at 9:08AM.

Dan Taft the chair of the drafting team provided a brief introduction and background on the project.

NPCC Antitrust Compliance Guidelines
The NPCC Antitrust Compliance Guidelines were read by Ruida Shu.

Agenda Items:

1. **Purpose of this Standard Drafting Team (SAR)**
   Dan Taft the chair brief everyone on the purpose of the drafting team.

2. **Review of Meeting Minutes**
   The drafting team reviewed part of the meeting minutes from November 22, 2016.

3. **Review of Comparison Table**
   Requirement 1:
   Brian Robinson reported all the feedbacks from TFSS.
   NY-ISO there are a few hundred MW compensatory load shedding scatter throughout the state
   Hydro Quebec has compensatory load shedding.
   Ontario uses compensatory load shedding for a number of smaller embedded generating units and/or considers these units in the Ontario UFLS program.
   John Pearson indicated that ISO-NE can remove the compensatory load shedding from their system and make adjustment on the relay curve.

   Action Item:
   --John Pearson will develop a draft redline on requirement 1.

   The drafting team agreed on making modifications to the existing standard and leave the requirement in the standard.
   The suggestion is to change the language "effective date" to an actual date so it is clear.

   Requirement 2:
   Dean Latulipe provided feedbacks from the members of SS38.
   The drafting team plan to remove the following language: "the generation facilities within its Planning Coordinator Area necessary to support the UFLS program performance characteristics".
   The SS38 group is in favor of perform studies on dispersed generation.
   Action Item:
   --John Pearson and Dean Latulipe will develop a draft redline on requirement 2.

   Requirement 3:
   The drafting team is considering retire requirement 3 or combine the language with requirement 1.

   Requirement 4:
   Action Item:
   --Dean Latulipe and John Pearson will draft another version of the redline for requirement 4. (The goal is to break the requirement into two sub requirements so the

requirement is more clear.) The requirement language will include islanding scenarios. (Appendix C)
The entities aggregating their UFLS programs could be covered by requirement 4.

Requirement 5:
The drafting team agreed to use the new drafted language by Dean Latulipe.
Action Item:
--John Pearson will add draft additional requirement language which will include provisions made for cases where settings need to be re-adjusted to meet the tolerances.
If a Distribution Provider or Transmission Owner cannot meet the tolerance and/or number of stages and frequency set points specified in Attachment C, Table 1 through 3, such Distribution Provider or Transmission Owner shall:

Requirement 6:
The drafting team agreed to retire the requirement.

Requirement 7:
Action Item:
--Dan Taft will draft the rationale box for requirement 7 and requirement 7.2 will be eliminated and 100MS will stay in the main text.

Requirement 8:
The drafting team agreed to use the draft requirement language.
Each Planning Coordinator shall develop and review settings for inhibit thresholds once per five calendar years (such as but not limited to voltage, current and time) to be utilized within its region's UFLS program.

Requirement 9:
The drafting team agreed to leave the requirement language as it is.

Requirement 10:
The drafting team agreed to swap requirement 10 with requirement 11.

Requirement 11:
The drafting team agreed to swap requirement 11 with requirement 10.

Requirement 12:
Action Item:
--Dan Taft will draft a rationale box for requirement 12.
Action Item:
--Tim Kucey will send out additional supporting material from VAR-002-4.

Requirement 13:
The drafting team decided to modify the language to “On or below the curve”.

Requirement 14:

The drafting team agreed to leave the requirement language as it is.

Requirement 15:
The drafting team agreed to remove the revision of 15.1 but keeping the other suggested language.

Requirement 16:
Action Item:

--Guy Zito will develop a draft redline on the compensatory load shedding requirement 16.

Requirement 17:
Action Item:
--Vincent Morissette will modify Attachment A.

Requirement 18:
The drafting team agreed to leave the requirement language as it is.

Requirement 19:
The drafting team agreed to leave the requirement language as it is.

Requirement 20:
The drafting team agreed on the following language for requirement 20:
The Planning Coordinator shall update its UFLS system study data at least once every five years. This system study shall include:
Action Item:
--Dean Latulipe will modify his draft language for 20.6.

Requirement 21:
Action Item:
-- Jeannette Gauthier will draft some examples for rationale box or Appendix to support and provide guidance on changes in the system that occurred less than a five-year time-frame.

Requirement 23:
The drafting team agreed to retire the requirement.

4. **PRC-006-NPCC-01 Redline**

5. **PRC-006-NPCC-1, PRC-006-2 and Directory 12**
Directory 12:
The drafting team will look to combining the curve between PRC-006-2 and Directory 12.
Action Item:
--Dean Latulipe, Vincent Morissette and Tim Kucey will work on taking the more stringent data and produce a new curve combining them.

Action Item:
--Dan Taft will check with Rich Burke on the background.

6. **Discussion on the process for approbation**

7. **Next Steps**
The SDT agreed on the next faced to face meeting will be on Thursday March 2, 2017 in NPCC Office.

Dan Taft adjourned the meeting at 3:56PM.

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.

A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**

2. **Number:** PRC-006-~~2~~ 3

3. **Purpose:** 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.

4. **Applicability:**

   4.1. Planning Coordinators

   4.2. 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:

   4.2.1 Transmission Owners

   4.2.2 Distribution Providers

   4.3. Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.

5. **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.

6. **Background:**

   PRC-006-2 was developed under Project 2008-02: Underfrequency Load Shedding (UFLS). The drafting team revised PRC-006-1 for the purpose of addressing the directive issued in FERC Order No. 763. *Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards*, 139 FERC ¶ 61,098 (2012).

B. Requirements and Measures

R1. Each Planning Coordinator shall develop and document criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement R1.

R2. Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

2.1. Those islands selected by applying the criteria in Requirement R1, and

2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System, and

2.3. A single island that includes all portions of the BES in either the Regional Entity area or the Interconnection in which the Planning Coordinator's area resides. If a Planning Coordinator's area resides in multiple Regional Entity areas, each of those Regional Entity areas shall be identified as an island. Planning Coordinators may adjust island boundaries to differ from Regional Entity area boundaries by mutual consent where necessary for the sole purpose of producing contiguous regional islands more suitable for simulation.

M2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s) as a basis for designing a UFLS program that meet the criteria in Requirement R2, Parts 2.1 through 2.3.

R3. Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-3~~2~~ - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-3~~2~~ - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

- Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES
- Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES
- Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

M3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement R3, Parts 3.1 through 3.3.

R4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-3~~2~~ - Attachment 1.

4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-3~~2~~ - Attachment 1.

4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-3~~2~~ - Attachment 1.

4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-3~~2~~ — Attachment 1.

4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-3~~2~~ — Attachment 1.

4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-3~~2~~ — Attachment 1.

4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4, Parts 4.1 through 4.7.

R5. Each Planning Coordinator, ~~-~~whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall coordinate its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island through one of the following: *[VRF: High][Time Horizon: Long-term Planning]*

- Develop a common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct a joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct an independent UFLS design assessment per Requirement R4 for the identified island, and in the event the UFLS design assessment fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet Requirement R3 and report these modifications as recommendations to the other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island and the ERO.

M5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall have dated evidence such as joint UFLS program design documents, reports describing a joint UFLS design assessment, letters that include recommendations, or other dated documentation demonstrating that it coordinated its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island per Requirement R5.

R6. Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities. *[VRF: Lower][Time Horizon: Long-term Planning]*

M6. Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it maintained a UFLS database for use in event analyses and assessments of the UFLS program per Requirement R6 at least once each calendar year, with no more than 15 months between maintenance activities.

R7. Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection within 30 calendar days of a request. *[VRF: Lower][Time Horizon: Long-term Planning]*

M7. Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within their Interconnection within 30 calendar days of a request per Requirement R7.

R8. Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. *[VRF: Lower][Time Horizon: Long-term Planning]*

M8. Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.

R9. Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for implementation, including any Corrective Action Plan, as determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. *[VRF: High][Time Horizon: Long-term Planning]*

M9. Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for implementation~~-~~, including any Corrective Action Plan, per Requirement R9.

R10. Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission. *[VRF: High][Time Horizon: Long-term Planning]*

M10. Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of its existing capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, per Requirement R10.

R11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

11.1. The performance of the UFLS equipment,

11.2. The effectiveness of the UFLS program.

M11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R11.

R12. Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

M12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted a UFLS design assessment per Requirements R12 and R4 if UFLS program deficiencies are identified in R11.

R13. Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall coordinate its event assessment (in accordance with Requirement R11) with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event through one of the following: *[VRF: Medium][Time Horizon: Operations Assessment]*

- Conduct a joint event assessment per Requirement R11 among the Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 that reaches conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 and where the assessment fails to reach conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, identify differences in the assessments that likely resulted in the differences in the conclusions and recommendations and report these differences to the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event and the ERO.

M13. Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall have dated evidence such as a joint assessment report, independent assessment reports and letters describing likely reasons for differences in conclusions and recommendations, or other dated documentation demonstrating it coordinated its event assessment (per Requirement R11) with all other Planning Coordinator(s) whose areas or portions of whose areas were also included in the same islanding event per Requirement R13.

R14. Each Planning Coordinator shall respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following *[VRF: Lower][Time Horizon: Long-term Planning]*:

14.1. UFLS program, including a schedule for implementation

14.2. UFLS design assessment

14.3. Format and schedule of UFLS data submittal

M14. Each Planning Coordinator shall have dated evidence of responses, such as e-mails and letters, to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program per Requirement R14.

R15. Each Planning Coordinator that conducts a UFLS design assessment under Requirement R4, R5, or R12 and determines that the UFLS program does not meet the performance characteristics in Requirement R3, shall develop a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area. *[VRF: High][Time Horizon: Long-term Planning]*

15.1. For UFLS design assessments performed under Requirement R4 or R5, the Corrective Action Plan shall be developed within the five-year time frame identified in Requirement R4.

15.2. For UFLS design assessments performed under Requirement R12, the Corrective Action Plan shall be developed within the two-year time frame identified in Requirement R12.

M15. Each Planning Coordinator that conducts a UFLS design assessment under Requirement R4, R5, or R12 and determines that the UFLS program does not meet the performance characteristics in Requirement R3, shall have a dated Corrective Action Plan and a schedule for implementation by the UFLS entities within its area, that was developed within the time frame identified in Part 15.1 or 15.2.

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

Each Planning Coordinator and UFLS 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:

- Each Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5, R12, R14, and R15, Measures M1, M2, M3, M4, M5, M12, M14, and M15 as well as any evidence necessary to show compliance since the last compliance audit.
- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to another Planning Coordinator since the last compliance audit in accordance with Requirement R7, Measure M7.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.
- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.
- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11, and R13, and Measures M11, and M13 for 6 calendar years.

If a Planning Coordinator or UFLS entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the retention 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 Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. OR The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.	The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.
R2	N/A	The Planning Coordinator identified an island(s) to	The Planning Coordinator identified an island(s) to serve	The Planning Coordinator identified an island(s) to serve

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		serve as a basis for designing its UFLS program but failed to include one (1) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.	as a basis for designing its UFLS program but failed to include two (2) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.	as a basis for designing its UFLS program but failed to include all of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3. OR The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program.
R3	N/A	The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet two (2) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s).,but failed to meet all the performance characteristic in Requirement R3, Parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions. OR The Planning Coordinator failed to develop a UFLS program

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				including notification of and a schedule for implementation by UFLS entities within its area
R4	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Requirement R4, Parts 4.1 through 4.7. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	N/A	N/A	N/A	The Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, failed to coordinate its UFLS program design through one of the manners described in Requirement R5.
R6	N/A	N/A	N/A	The Planning Coordinator failed to maintain a UFLS database for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.
R7	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 30 calendar days and up to and including 40 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request. OR The Planning Coordinator failed to provide its UFLS database to

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				other Planning Coordinators.
R8	The UFLS entity provided data to its Planning Coordinator(s) less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.
R9	The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS program design and schedule for implementation, including	The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for implementation, including any	The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for implementation, including any	The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for implementation, including any Corrective Action Plan, as determined by the

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	any Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.	Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.	Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.	Planning Coordinator(s) area in which it owns assets.
R10	The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.	The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.	The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.	The Transmission Owner provided less than 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.
R11	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than one year but less than or equal to 13 months of actuation.	assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.	the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 14 months but less than or equal to 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate one (1) of the Parts as specified in Requirement R11, Parts11.1 or 11.2.	evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluate the Parts as specified in Requirement R11, Parts 11.1 and 11.2. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate all of the Parts as specified in Requirement R11, Parts 11.1 and 11.2.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, failed to conduct and document a UFLS design assessment to consider the identified deficiencies.
R13	N/A	N/A	N/A	The Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, failed to coordinate its UFLS event assessment with all

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event in one of the manners described in Requirement R13
R14	N/A	N/A	N/A	The Planning Coordinator failed to respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes were made or reasons why changes were not made to the items in Parts 14.1 through 14.3.
R15	N/A	The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement R3, and developed a Corrective Action Plan and a	The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement R3, and developed a Corrective Action Plan and a	The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement R3, but failed to develop a Corrective Action Plan and a

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		schedule for implementation by the UFLS entities within its area, but exceeded the permissible time frame for development by a period of up to 1 month.	schedule for implementation by the UFLS entities within its area, but exceeded the permissible time frame for development by a period greater than 1 month but not more than 2 months.	schedule for implementation by the UFLS entities within its area. OR The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement R3, and developed a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area, but exceeded the permissible time frame for development by a period greater than 2 months.

D. Regional Variances

D.A. Regional Variance for the Quebec Interconnection

The following Interconnection-wide variance shall be applicable in the Quebec Interconnection and replaces, in their entirety, Requirements R3 and R4 and the violation severity levels associated with Requirements R3 and R4.

Rationale for Requirement D.A.3:

There are two modifications for requirement D.A.3 :

1. 25% Generation Deficiency : Since the Quebec Interconnection has no potential viable BES Island in underfrequency conditions, the largest generation deficiency scenarios are limited to extreme contingencies not already covered by RAS.

Based on Hydro-Québec TransÉnergie Transmission Planning requirements, the stability of the network shall be maintained for extreme contingencies using a case representing internal transfers not expected to be exceeded 25% of the time.

The Hydro-Québec TransÉnergie defense plan to cover these extreme contingencies includes two RAS (RPTC- generation rejection and remote load shedding -and TDST - a centralized UVLS) and the UFLS.

2. Frequency performance curve (attachment 1A) : Specific cases where a small generation deficiency using a peak case scenario with the minimum requirement of spinning reserve can lead to an acceptable frequency deviation in the Quebec Interconnection while stabilizing between the PRC-006-2 requirement (59.3 Hz) and the UFLS anti-stall threshold (59.0 Hz).

An increase of the anti-stall threshold to 59.3 Hz would correct this situation but would cause frequent load shedding of customers without any gain of system reliability. Therefore, it is preferable to lower the steady state frequency minimum value to 59.0 Hz.

The delay in the performance characteristics curve is harmonized between D.A.3 and R.3 to 60 seconds.

Rationale for Requirements D.A.3.3. and D.A.4:

The **Q**uebec Interconnection has its own definition of BES. In Quebec, the vast majority of BES generating plants/facilities are not directly connected to the BES. For simulations to take into account sufficient generating resources D.A.3.3 and D.A.4 need simply refer to BES generators, plants or facilities since these are listed in a Registry approved by Québec's Regulatory Body (Régie de l'Énergie).

D.A.3. Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from ~~an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)~~ each of these extreme events:

- Loss of the entire capability of a generating station.
- Loss of all transmission circuits emanating from a generating station, switching station, substation or dc terminal.
- Loss of all transmission circuits on a common right-of-way.
- Three-phase fault with failure of a circuit breaker to operate and correct operation of a breaker failure protection system and its associated breakers.
- Three-phase fault on a circuit breaker, with normal fault clearing.
- The operation or partial operation of a RAS for an event or condition for which it was not intended to operate.

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~~.~~ *[VRF: High][Time Horizon: Long-term Planning]*

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D.A.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-3~~2~~ - Attachment 1A, either for ~~30~~ 60 seconds or until a steady-state condition between 59.~~3~~ 0 Hz and 60.7 Hz is reached, and

D.A.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-3~~2~~ - Attachment 1A, either for ~~30~~ 60 seconds or until a steady-state condition between 59.~~3~~ 0 Hz and 60.7 Hz is reached, and

D.A.3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each Quebec BES generator bus and associated generator step-up transformer high-side bus ~~associated with each of the following:~~

~~**DA.3.3.1.** Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the BES~~

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~~**DA.3.3.2.** Generating plants/facilities greater than 50 MVA (gross aggregate nameplate rating) directly connected to the BES~~

~~**DA.3.3.3.** Facilities consisting of one or more units connected to the BES at a common bus with total generation above 50 MVA gross nameplate rating.~~

M.D.A.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement D.A.3 Parts D.A.3.1 through D.A.3.3.

D.A.4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.A.3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*

D.A.4.1 Underfrequency trip settings of individual generating units that are part of Quebec BES plants/facilities ~~with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES~~ that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-3~~2~~ - Attachment 1A, and

D.A.4.2 Overfrequency trip settings of individual generating units that are part of Quebec BES plants/facilities ~~with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES~~ that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-3~~2~~ - Attachment 1A, and

D.A.4.3 Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M.D.A.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement D.A.4 Parts D.A.4.1 through D.A.4.3.

D#	Lower VSL	Moderate VSL	High VSL	Severe VSL
DA3	N/A	The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Parts D.A.3.1, D.A.3.2, or D.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Parts D.A.3.1, D.A.3.2, or D.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Parts D.A.3.1, D.A.3.2, and D.A.3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to develop a UFLS program including notification of and a schedule for implementation by UFLS entities within its area.
DA4	N/A	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined~~s~~ through dynamic simulation whether the UFLS program design ~~meets~~ met the performance characteristics in Requirement D.A.3 but the simulation failed to include one	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined~~s~~ through dynamic simulation whether the UFLS program design ~~meets~~ met the performance characteristics in Requirement D.A.3 but the simulation failed to include two	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined~~s~~ through dynamic simulation whether the UFLS program design ~~meets~~ met the performance characteristics in Requirement D.A.3 but the simulation failed to include all of

D#	Lower VSL	Moderate VSL	High VSL	Severe VSL
		(1) of the items as specified in Parts D.A.4.1, D.A.4.2 or D.A.4.3.	(2) of the items as specified in Parts D.A.4.1, D.A.4.2 or D.A.4.3.	the items as specified in Parts D.A.4.1, D.A.4.2 and D.A.4.3. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.A.3

D.B. Regional Variance for the Western Electricity Coordinating Council

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R1, R2, R3, R4, R5, R11, R12, and R13.

D.B.1. Each Planning Coordinator shall participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that develops and documents criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES) that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

M.D.B.1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria, developed as part of the joint regional review with other Planning Coordinators in the WECC Regional Entity area to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement D.B.1.

D.B.2. Each Planning Coordinator shall identify one or more islands from the regional review (per D.B.1) to serve as a basis for designing a region-wide coordinated UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

D.B.2.1. Those islands selected by applying the criteria in Requirement D.B.1, and

D.B.2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System.

M.D.B.2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s), from the regional review (per D.B.1), as a basis for designing a region-wide coordinated UFLS program that meet the criteria in Requirement D.B.2 Parts D.B.2.1 and D.B.2.2.

D.B.3. Each Planning Coordinator shall adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

D.B.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-3~~2~~ - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

D.B.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-~~2~~3 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

D.B.3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

D.B.3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

D.B.3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

D.B.3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

M.D.B.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its adoption of a UFLS program, coordinated across the WECC Regional Entity area, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement D.B.3 Parts D.B.3.1 through D.B.3.3.

D.B.4. Each Planning Coordinator shall participate in and document a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

D.B.4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-~~2~~3 - Attachment 1.

D.B.4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-~~2~~3 - Attachment 1.

D.B.4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-3~~2~~ - Attachment 1.

D.B.4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-3~~2~~ — Attachment 1.

D.B.4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-3~~2~~ — Attachment 1.

D.B.4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-3~~2~~ — Attachment 1.

D.B.4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M.D.B.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its participation in a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area that demonstrates it meets Requirement D.B.4 Parts D.B.4.1 through D.B.4.7.

D.B.11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall participate in and document a coordinated event assessment with all affected Planning Coordinators to conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

D.B.11.1. The performance of the UFLS equipment,

D.B.11.2 The effectiveness of the UFLS program

M.D.B.11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a coordinated event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement D.B.11.

D.B.12. Each Planning Coordinator, in whose islanding event assessment (per D.B.11) UFLS program deficiencies are identified, shall participate in and document a coordinated UFLS design assessment of the UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

M.D.B.12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a UFLS design assessment per Requirements D.B.12 and D.B.4 if UFLS program deficiencies are identified in D.B.11.

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
D.B.1	N/A	The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands OR The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands	The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands	The Planning Coordinator failed to participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas that may form islands

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
D.B.2	N/A	N/A	The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include one (1) of the parts as specified in Requirement D.B.2, Parts D.B.2.1 or D.B.2.2	The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include all of the parts as specified in Requirement D.B.2, Parts D.B.2.1 or D.B.2.2 OR The Planning Coordinator failed to identify any island(s) from the regional review to serve as a basis for designing its UFLS program.
D.B.3	N/A	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement D.B.3, Parts D.B.3.1, D.B.3.2, or D.B.3.3 in simulations of underfrequency	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Requirement D.B.3, Parts D.B.3.1, D.B.3.2, or D.B.3.3 in simulations of underfrequency conditions	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Requirement D.B.3, Parts D.B.3.1, D.B.3.2, and D.B.3.3 in simulations of underfrequency

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		conditions		conditions OR The Planning Coordinator failed to adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area.
D.B.4	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include one (1) of the items as specified in Requirement D.B.4, Parts D.B.4.1 through	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include two (2) of the items as specified in Requirement D.B.4, Parts D.B.4.1 through D.B.4.7.	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include three (3) of the items as specified in Requirement D.B.4, Parts D.B.4.1 through D.B.4.7.	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include four (4) or more of the items as specified in Requirement D.B.4, Parts D.B.4.1 through D.B.4.7.

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	D.B.4.7.			OR The Planning Coordinator failed to participate in and document a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2
D.B.11	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement D.B.11, Parts	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement D.B.11, Parts	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement D.B.11, Parts

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2 within a time greater than one year but less than or equal to 13 months of actuation.	D.B.11.1 and D.B.11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.	D.B.11.1 and D.B.11.2 within a time greater than 14 months but less than or equal to 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate one (1) of the parts as specified in Requirement D.B.11, Parts D.B.11.1 or D.B.11.2.	D.B.11.1 and D.B.11.2 within a time greater than 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to participate in and document a coordinated event assessment with all Planning Coordinators whose areas or portion of whose areas were also included in the same island event and evaluate the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate all of the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2.
D.B.12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, failed to participate in and document a coordinated UFLS design assessment of the

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies

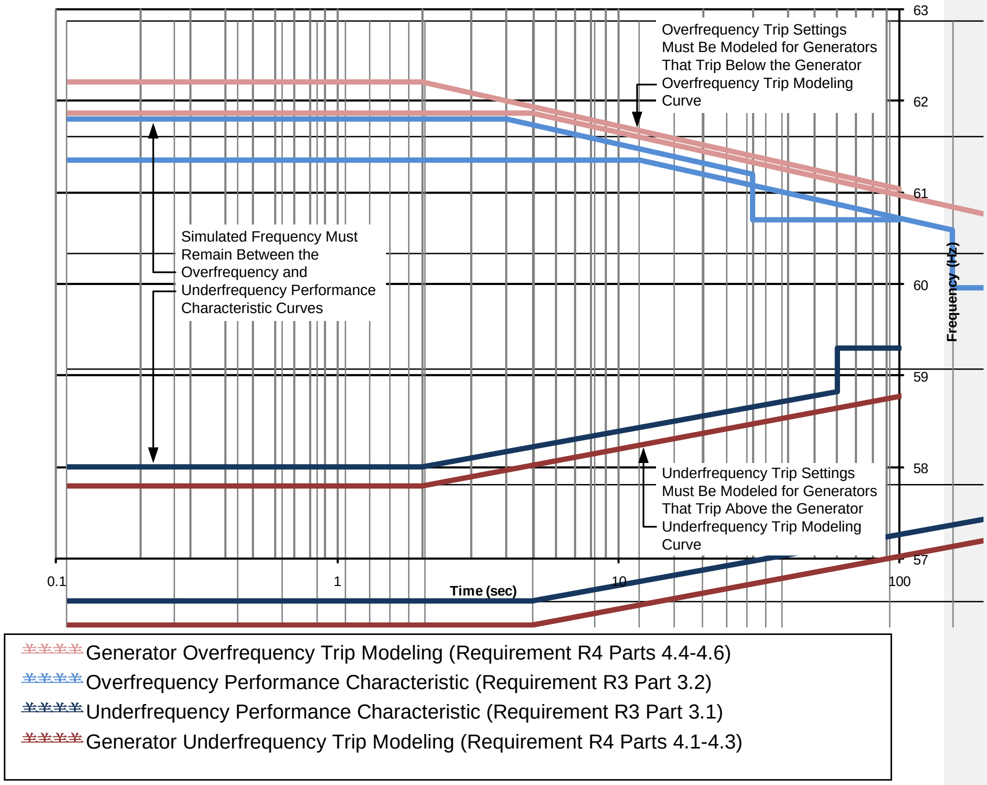
E. Associated Documents

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 25, 2010	Completed revision, merging and updating PRC-006-0, PRC-007-0 and PRC-009-0.	
1	November 4, 2010	Adopted by the Board of Trustees	
1	May 7, 2012	FERC Order issued approving PRC-006-1 (approval becomes effective July 10, 2012)	
1	November 9, 2012	FERC Letter Order issued accepting the modification of the VRF in R5 from (Medium to High) and the modification of the VSL language in R8.	
2	November 13, 2014	Adopted by the 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. Revisions to existing Requirement R9 and R10 and addition of new Requirement R15.

PRC-006-~~2~~ 3 – Attachment 1

Underfrequency Load Shedding Program
Design Performance and Modeling Curves for
Requirements R3 Parts 3.1-3.2 and R4 Parts 4.1-4.6

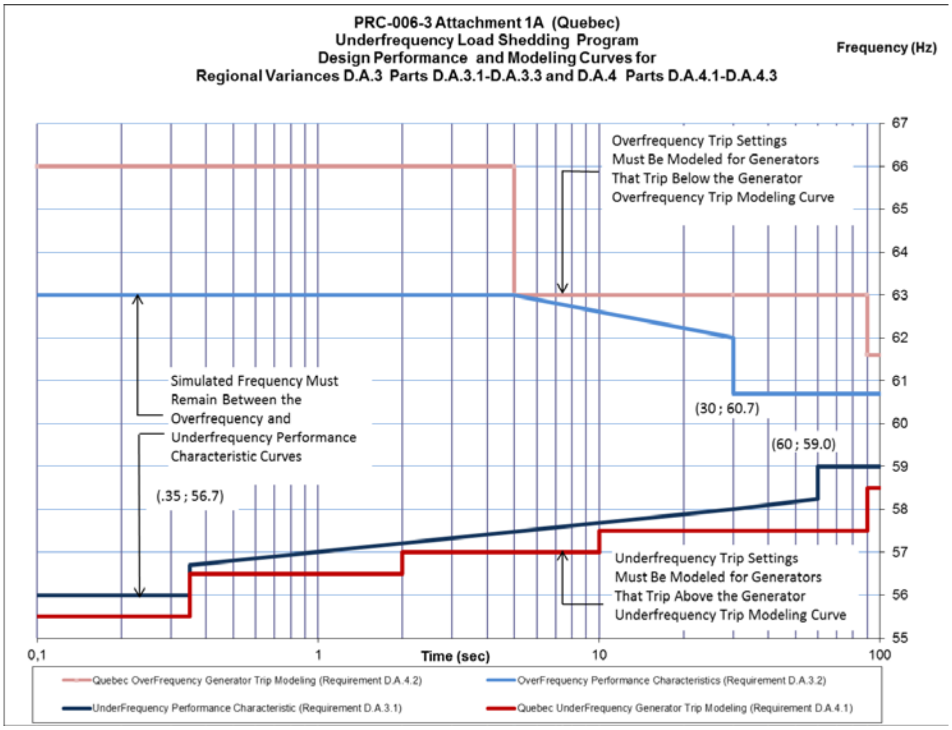


Curve Definitions

Generator Overfrequency Trip Modeling		Overfrequency Performance Characteristic		
t ≤ 2 s	t > 2 s	t ≤ 4 s	4 s < t ≤ 30 s	t > 30 s
f = 62.2 Hz	f = -0.686log(t) + 62.41 Hz	f = 61.8 Hz	f = -0.686log(t) + 62.21 Hz	f = 60.7 Hz

Generator Underfrequency Trip Modeling	Underfrequency Performance Characteristic

t ≤ 2 s	t > 2 s	t ≤ 2 s	2 s < t ≤ 60 s	t > 60 s
f = 57.8 Hz	f = 0.575log(t) + 57.63 Hz	f = 58.0 Hz	f = 0.575log(t) + 57.83 Hz	f = 59.3 Hz


PRC-006-3 Attachment 1A (Quebec)
Underfrequency Load Shedding Program
Design Performance and Modeling Curves for
Regional Variances D.A.3 Parts D.A.3.1-D.A.3.3 and D.A.4 Parts D.A.4.1-D.A.4.3
Frequency (Hz)
Overfrequency Trip Settings Must Be Modeled for Generators That Trip Below the Generator Overfrequency Trip Modeling Curve
Simulated Frequency Must Remain Between the Overfrequency and Underfrequency Performance Characteristic Curves
(30 ; 60.7)
(60 ; 59.0)
(.35 ; 56.7)
Underfrequency Trip Settings Must Be Modeled for Generators That Trip Above the Generator Underfrequency Trip Modeling Curve
Time (sec)
0,1
1
10
100
67
66
65
64
63
62
61
60
59
58
57
56
55
Quebec OverFrequency Generator Trip Modeling (Requirement D.A.4.2)
OverFrequency Performance Characteristics (Requirement D.A.3.2)
UnderFrequency Performance Characteristic (Requirement D.A.3.1)
Quebec UnderFrequency Generator Trip Modeling (Requirement D.A.4.1)

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 R9:

The "Corrective Action Plan" language was added in response to the FERC directive from Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a Planning Coordinator (PC) assessment. The revised language adds clarity by requiring that each UFLS entity follow the UFLS program, including any Corrective Action Plan, developed by the PC.

Also, to achieve consistency of terminology throughout this standard, the word "application" was replaced with "implementation." (See Requirements R3, R14 and R15)

Rationale for R10:

The "Corrective Action Plan" language was added in response to the FERC directive from Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a PC assessment. The revised language adds clarity by requiring that each UFLS entity follow the UFLS program, including any Corrective Action Plan, developed by the PC.

Also, to achieve consistency of terminology throughout this standard, the word "application" was replaced with "implementation." (See Requirements R3, R14 and R15)

Rationale for R15:

Requirement R15 was added in response to the directive from FERC Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a PC assessment. Requirement R15 addresses the FERC directive by making explicit that if deficiencies are identified as a result of an assessment, the PC shall develop a Corrective Action Plan and schedule for implementation by the UFLS entities.

A "Corrective Action Plan" is defined in the NERC Glossary of Terms as, "a list of actions and an associated timetable for implementation to remedy a specific problem." Thus, the Corrective Action Plan developed by the PC will identify the specific timeframe for an entity to implement corrections to remedy any deficiencies identified by the PC as a result of an assessment.

Implementation Plan

Reliability Standard PRC-006-3 – Automatic Underfrequency Load Shedding

Revisions to Address Automatic Underfrequency Load Shedding (UFLS) Requirements for the Quebec Interconnection

Applicable Standard(s)

- PRC-006-3 – Automatic Underfrequency Load Shedding

Requested Retirement(s)

- PRC-006-2 – Automatic Underfrequency Load Shedding

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

Background

The PRC-006-3 Regional Standard Drafting Team revised Section D.A of PRC-006-2, Regional Variance for the Quebec Interconnection to address two specific problems regarding UFLS requirements for the Quebec Interconnection :

1. To meet the PRC-006-2 59.3 Hz requirement for scenarios where Quebec has a small generation deficiency (between 4 and 6 percent), those scenarios would require modifications to the current settings of the UFLS program to the threshold of 59.3 Hz; this would cause unacceptable and frequent load shedding without any improvement to System reliability.

2. Because the Quebec Interconnection itself is an island with unique generation characteristics and RAS (SPS) applications, Section D.A.3 in PRC-006-2 needs to be revised to define a more accurate generation deficiency scenario applicable to the Quebec Interconnection.

The continent-wide Requirements and all other aspects of the standard remain unchanged from PRC-006-2.

Effective Date

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is one month after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

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 one month after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Reliability Standard PRC-006-2 shall be retired immediately prior to the effective date of PRC-006-3 in the particular jurisdiction in which the revised standard is becoming effective.

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

PRC-006-3 Automatic Underfrequency Load Shedding
Revisions to Quebec Variance
Comment Form

Background Information

The revisions to the PRC-006-3 Automatic Underfrequency Load Shedding Quebec Variance have been developed to address two specific problems regarding UFLS requirements for the Quebec Interconnection:

1. To meet the PRC-006-2 59.3 Hz requirement for circumstances when Quebec has a small generation deficiency (between 4 and 6 percent). This scenario requires modifications to the current settings of the UFLS program to avoid unacceptable and frequent load shedding without any improvement to system reliability.
2. The Quebec Interconnection itself is an island with unique generation characteristics and Remedial Action Scheme (RAS) applications. Therefore, Section D.A.3 in PRC-006-2 needs to be revised to define a more accurate generation deficiency scenario applicable to the Quebec Interconnection.
   The continent-wide PRC-006-2 requirements and all other aspects of the standard remain unchanged.

The comment period is open from October 31, 2016 through December 15, 2016.
Please submit your comments using this form and upload it to the NPCC website or provide your responses directly:
PRC-006-3 Automatic Underfrequency Load Shedding Quebec Variance

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Do you agree with the proposed revisions to Quebec Variance section of the PRC-006-2 Automatic Underfrequency Load Shedding?

Yes ☐

No ☒

Comments:

HQT in its Reliability Coordinator role in Québec (RC) proposed the Québec Variance to the Régie at the same time as HQT in its Planning Coordinator role (PC) proposed it to NPCC. However, during the revisions of the French and English versions, a one word typo occurred in the version proposed to NPCC.

In order to harmonize the language between the standard submitted to the Régie with the standard PRC-006-3 to be adopted by NPCC/NERC, HQT in its RC role requests NPCC consider the following change: the term 'one of' should be replaced by 'each of' at paragraph D.A.3 in the Quebec variance. This minor change results in clearer and more applicable standard language and ensures greater reliability for the Interconnection.

HQT in its PC role supports the modification since the resulting text reflects its original intent, it reflects the PC's planning criteria and practices and it is better for the reliability of the Interconnexion.

The text for D.A.3 becomes:

> **D.A.3**. Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from ~~one~~ each of these extreme events: Loss of the entire capability of a generating station.

Hydro Québec
TransÉnergie

Une division d'Hydro-Québec

August 26, 2016

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VIA EMAIL

Guy V. Zito
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Subject: PRC-006-3 Automatic UFLS Québec Variance – CEAP Phase 2

Following the end of the comment period for PRC-006-3 Quebec variance on August 22, 2016 it is our understanding that the next step in the process toward adoption would normally be the second phase of the Cost Effective Analysis Process (CEAP). Considering that only the Quebec Interconnection is concerned by the changes in PRC-006-3 and that the proposed revision does not incur any additional costs for us since it reflects current planning criteria, Hydro-Québec TransÉnergie proposes to waive phase 2 of the CEAP. Please let us know if this is acceptable to NPCC.

Regards.

Caroline Dupuis, eng.
Manager of Reliability Standards and Regulatory Compliance
Direction Normes de fiabilité et conformité réglementaire
Direction principale – Contrôle des mouvements d'énergie et exploitation du réseau
Hydro-Québec TransÉnergie

c.c. Sylvain Clermont (HQT Director of Reliability Standards and Regulatory Compliance)
Patrick Doyle (HQT manager of SRPI, Direction Planification)
Jeannette Gauthier (member of PRC-006-3 SDT)
Vincent Morissette (SME and member of PRC-006-3 SDT)
Si Truc Phan (RSC contact for PRC-006-3)
Ruida Shu (NPCC coordinator for PRC-006-3)

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Alternate

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket Nos. RM05-17-000** **RM05-25-000** **RM06-16-000**

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
INFORMATIONAL FILING OF RELIABILITY STANDARDS DEVELOPMENT PLAN
2017-2019

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December 16, 2016

TABLE OF CONTENTS

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket Nos. RM05-17-000** **RM05-25-000** **RM06-16-000**

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION INFORMATIONAL FILING OF RELIABILITY STANDARDS DEVELOPMENT PLAN 2017-2019

The North American Electric Reliability Corporation ("NERC") hereby submits its 2017-2019 Reliability Standards Development Plan ("2017 Development Plan") in accordance with Section 310 of the NERC *Rules of Procedure*.[1] The 2017 Development Plan, included herein as **Attachment A**, provides a status update on active development projects, a forecast of future work to be undertaken by industry participants and NERC throughout the upcoming year, and an analysis comparing completed projects and development accomplishments with the prior year's Reliability Standards Development Plan. The NERC Board of Trustees ("NERC Board") approved the 2017 Development Plan on November 2, 2016. NERC submits this filing and attached 2017 Development Plan for informational purposes only.

[1] Section 310 of NERC's *Rules of Procedure* requires NERC to develop and provide an annual Reliability Standards Development Plan for development of Reliability Standards to the applicable governmental authorities. Under that Section, NERC is also required to consider comments and priorities of the applicable governmental authorities in any updates made to the plan, and the plan should compare current accomplishments with the prior plan. *See* NERC's Rules of Procedure, accessible online at: http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx.

I. NOTICES AND COMMUNICATIONS

Notices and communications regarding this filing may be addressed to the following:

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II. BACKGROUND

Pursuant to Section 310 of the NERC Rules of Procedure, NERC submitted an initial version of a plan for Reliability Standards development, entitled the *Reliability Standards Development Plan: 2007–2009,* to the Federal Energy Regulatory Commission ("FERC" or "Commission") in 2006. NERC has since updated the plan annually, and the 2017-2019 version of the plan is presented in this filing. Consistent with previous versions, the 2017 Development Plan is filed for informational purposes and no specific Commission action is requested at this time.

The 2017 Development Plan is intended to:

1. Serve as a management tool to guide and coordinate the development of Reliability Standards and provide benchmarks for assessing progress;
2. Serve as a communications tool for coordinating standards development work with applicable governmental agencies in the United States and Canada and for engaging stakeholders in Reliability Standards development activities; and
3. Provide a basis for developing annual plans and budgets for the NERC Reliability Standards Program.

As with each prior year's plan, NERC obtained stakeholder input on the 2017 Development Plan. As detailed in Section III, NERC submits this filing to summarize the 2017

Development Plan and inform the Commission and other interested parties of projects noted in the 2016 Development Plan that will continue into 2017.

III. 2017 DEVELOPMENT PLAN

A. Summary of 2017 Development Plan

The 2017 Development Plan identifies the current plans and priorities for development and modification of NERC Reliability Standards in the immediate three-year time horizon. Building upon the efforts of prior year Reliability Standard Development Plans, the 2017 Development Plan focuses on projects related to new Commission directives, emerging risks, and standard authorization requests, as well as projects related to periodic reviews and NERC's standards grading initiative. The addition of the standards grading metric, which uses an enhanced version of the template developed by the Independent Experts Review Panel ("IERP"),[2] will be used to inform the periodic reviews as to the quality and content of the standards.

As with the 2016 Development Plan, periodic reviews will continue at a measured pace, as NERC plans to complete a number of reviews each year while aligning these reviews with several strategic considerations to review the quality and content of standards in an efficient, effective manner. The 2017 Development Plan identifies each Reliability Standard or standard family that is a candidate for review through the periodic review process, and it highlights prioritization of all future projects with consideration of, among other things, communication with NERC's Reliability Issues Steering Committee ("RISC"), potential Commission directives, and industry input.

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[2] *See* infra n. 4.

NERC anticipates that the Reliability Standards development work outlined in the 2017 Development Plan will be dynamic and will be updated periodically as projects are completed or as new needs are identified and projects are considered. NERC also recognizes Reliability Standards development in 2017 may require flexibility in planning to ensure that activities are given appropriate resources and priority.

B. 2016 Progress Report

The 2016 Development Plan identified eight (8) standard development projects that would be initiated in 2016 or continue from 2015. The projects and their current status are noted below.

Projects Completed in 2016

The following projects identified in the 2016 Development Plan were completed in 2016:

- Project 2009-02 - Real-time Reliability Monitoring and Analysis Capabilities
- Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes
- Project 2010-07.1 Vegetation Management
- Project 2015-07 Internal Communications Capabilities FERC Order No. 808 Directive
- Project 2014-02 Modifications to CIP Standards

In addition, the following projects identified in the 2015 Development Plan, which were noted as in progress in NERC's 2015 informational filing,[3] were completed in 2016:

- Project 2007-06 System Protection Coordination
- Project 2007-06.2 System Protection Coordination
- Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls
- Project 2010-14.2.2 Phase 2 of Balancing Authority Reliability-based Controls

Projects Continuing in 2017

The following projects identified in the 2016 Development Plan will continue into 2017:

- Project 2015-08 Emergency Operations

[3] *See North American Electric Reliability Corporation Informational Filing of Reliability Standards Development Plan 2016-2018*, filed in these dockets on December 30, 2015.

- Project 2015-09 System Operating Limits
- Project 2015-10 Single Points of Failure TPL-001

Following the development of the 2016 Development Plan, NERC also initiated several projects in response to Commission directives, two periodic review projects, and two interpretation projects. These projects are identified and prioritized in the 2017 Development Plan, as described in the following section.

C. Prioritization of 2017 Projects

For each new Reliability Standard Project identified in the 2017 Development Plan, the NERC Standards Committee has assigned a priority of either high, medium, or low. These rankings are in addition to priority assignments made in previous plans for ongoing projects, and the assignments are based on, among other things, RISC category rankings, regulatory directives, regulatory deadlines, Reliability Standards that are candidates for retirement, and recommendations from the IEPR report.[4] The new and continuing projects identified in the 2017 Development Plan and their assigned priority category are provided below.

High Priority

- Project 2013-03 Geomagnetic Disturbance Mitigation[5]
- Project 2015-10 Single Points of Failure TPL-001[6]
- Project 2016-01 Modifications to TOP and IRO Standards[7]

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[4] NERC retained a group of industry experts, referred to as the IERP, to independently review NERC Reliability Standards and produce a report, setting a foundation for a plan that will result in a set of clear, concise, and sustainable body of Reliability Standards. In this report, which was issued in June 2013, the IERP provided various recommendations, including suggestions for retirement of certain requirements in various Reliability Standards. The IERP report can be accessed online at: http://www.nerc.com/pa/Stand/Standards%20Development%20Plan%20Library/Standards_Independent_Experts_Review_Project_Report.pdf.

[5] This project was initiated in 2016 in response to Commission directives in Order No. 830 to modify Reliability Standard TPL-007-1. *See Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, Order No. 830, 156 FERC ¶ 61,215 (Sep. 22, 2016). This project, which was added to the 2017 Development Plan in November 2016, has been assigned a high priority based on the regulatory deadlines established in Order No. 830.

[6] This project was identified in the 2016 Development Plan and will continue into 2017.

[7] This project was initiated in 2016 in response to Commission directives in Order No. 817 to make certain modifications to the revised TOP and IRO standards submitted for Commission approval in March 2015. *See*

- Project 2016-02 Modifications to CIP Standards[8]
- Project 2016-03 Cyber Security Supply Chain Management[9]

Medium Priority

- Project 2015-08 Emergency Operations[10]
- Project 2015-09 System Operating Limits[11]
- 2016-EPR-01 Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards – PER-001, PER-003, PER-004[12]
- 2016-EPR-02 Enhanced Periodic Review of Voltage and Reactive Standards – VAR-001, VAR-002[13]

Medium to Low Priority[14]

- Project 2015-INT-03 Interpretation of TOP-002.2.1b for FMPP[15]

Low Priority

- *No currently active projects have been identified as Low priority.*

As explained in the 2017 Development Plan, NERC does not anticipate development of any specific projects in 2017; rather, projects will be initiated based on: (i) periodic review recommendations to revise existing standards; (ii) emerging risks identified by the Commission, the RISC, NERC, or industry participants; or (iii) modifications to existing standards as directed by the Commission in future orders.

Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards, Order No. 817, 153 FERC ¶ 61,178 (Nov. 19, 2015).

8 This project was initiated in 2016 in response to Commission directives in Order No. 822 to develop certain modifications to improve the CIP Reliability Standards. *See Revised Critical Infrastructure Protection Reliability Standards*, Order No. 822, 154 FERC ¶ 61,037 (Jan. 21, 2016).

9 This project was initiated in 2016 in response to Commission directives in Order No. 829 to develop a new or modified standard to address supply chain risk management. *See Revised Critical Infrastructure Protection Reliability Standards*, Order No. 829, 156 FERC ¶ 61,050 (Jul. 21, 2016). This project, which was added to the 2017 Development Plan in November 2016, has been assigned a high priority due to the regulatory deadlines established in Order 829.

10 This project was identified in the 2016 Development Plan and will continue into 2017.

11 This project was identified in the 2016 Development Plan and will continue into 2017.

12 This periodic review project was initiated in 2016 and will continue into 2017.

13 This periodic review project was initiated in 2016 and will continue into 2017.

14 Project 2015-INT-01 Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec), assigned a Medium to Low Priority in the 2017 Development Plan, was completed in November 2016.

15 This project was initiated in 2016 in response to a Request for Interpretation and will continue into 2017.

The industry-led Standards Committee has prioritized current and upcoming projects, as communicated through prioritization schedules and project plans, to ensure that development moves at a measurable and sustainable pace.

D. Periodic Reviews

As indicated in the 2017 Development Plan, at least two periodic review projects will commence in 2017 from the following list of eligible standards or standards families:

- BAL and INT families (BAL-001 and INT-004, INT-006, INT-009, and INT-010)
- EOP-010
- FAC-003-4
- FAC-008-3
- NUC-001-3
- The PRC family of standards

Attachment 1 to the 2017 Development Plan describes the criteria that is used to determine which standards are eligible for periodic review and the specific elements which are to be considered in prioritizing the periodic reviews. An important consideration in this determination is the standards grade assigned by the Enhanced Periodic Review Standing Review Team. Beginning in 2016, this team was tasked with using metrics from the IERP to assign grades of content and quality to eligible standards. Attachment 2 to the 2017 Development Plan lists the final grades for the standards graded in 2016. In addition, the prioritization of periodic reviews may be informed by RISC category rankings, outstanding regulatory directives, and IERP findings and recommendations, among other factors.

IV. CONCLUSION

As discussed above, the 2017 Development Plan was developed in accordance with Section 310 of the NERC Rules of Procedure and identifies the current plans and priorities for development and modification of NERC Reliability Standards in the immediate three-year time horizon. NERC submits this filing and the attached 2017 Development Plan for informational purposes only.

Respectfully submitted,

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Date: December 16, 2016

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 16th day of December, 2016.

/s/ Lauren A. Perotti

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ATTACHMENT A

RELIABILITY STANDARDS DEVELOPMENT PLAN

2017-2019

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Standards Development Plan

2017–2019

November 2, 2016

RELIABILITY | ACCOUNTABILITY




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Table of Contents

Background

The 2016–2018 Reliability Standards Development Plan (RSDP) set forth a transitional plan to bring the body of NERC Reliability Standards to the initial stage of "steady state"[1] by addressing remaining Federal Energy Regulatory Commission (FERC) directives and recommendations to retire standard requirements. It specifically included the Integration of Variable Generation Task Force and Essential Reliability Services Working Group (ERSWG) recommendations, and called for continued communication with the Reliability Issues Steering Committee (RISC) on emerging risks. The 2016-2018 RSDP recognized the need to address subsequent FERC directives and Standard Authorization Requests (SARs), and the need to enhance communication through industry feedback loops. The 2016-2018 RSDP also planned for initial Enhanced Periodic Reviews (EPR) of the PER and VAR standards, which successfully commenced in 2016.

Pursuant to the NERC Rules of Procedure, section 310, NERC is required to develop and provide to applicable governmental authorities an annual RSDP for Reliability Standards development. NERC is also required to consider the comments and priorities of the applicable governmental authorities in developing and updating the annual RSDP. Each annual RSDP must include a progress report comparing results achieved to the prior year's RSDP. NERC also includes the NERC Standards Committee review during RSDP development, and posts the RSDP for industry comment.

[1] For the purposes of the RSDP, "steady state" means a stable set of clear, concise, high-quality, and technically sound Reliability Standards that are results-based, including retirement of requirements that do little to promote reliability.

Executive Summary

The 2017–2019 RSDP recognizes the diligent work of the last few years to bring the body of NERC Reliability Standards to the initial stage of steady state while transitioning to focusing on EPRs, FERC directives, emerging risks, SARs, and the standards grading initiative. The 2017-2019 RSDP contemplates that the work of the ERSWG may result in one or more SARs and subsequent standards projects.

As with the 2016-2018 RSDP, EPRs will occur at a measured pace, compared to the level of activity and pace of standards development during the past three years,[2] and they will be aligned with strategic considerations of reviewing standard families[3] that are interrelated. The addition of the standards grading metric, which uses an enhanced version of the template developed by the Independent Experts Review Panel (IERP), will inform the EPRs as to the quality and content of the standards.[4]

The 2017-2019 RSDP also includes plans for completing the EPRs initiated in 2016, and for commencing additional EPRs in 2017.

While most of the work in the next three years will focus on EPRs, there may be new or emerging risks identified that would generate new standards development projects. NERC and the Standards Committee will continue to seek input and recommendations from the RISC with regard to emerging or potential risks to reliability that may require revisions to existing standards or new standards development.

The 2017-2019 RSDP provides insight into standards development activities anticipated at the time of publication so that stakeholders may make available appropriate resources to accomplish these standards development objectives.

[2] The Standards Committee approved an EPR template on September 30, 2014 and presented it to the NERC Board of Trustees on November 12, 2014 as part of the Standard Committee's update. The template includes background information and questions to guide a comprehensive review of the standard(s) by the EPR team, and serves as documentation of the EPR team's considerations and recommendations.

[3] In some cases, a narrower review of a standard will likely be appropriate. For example, there are not necessarily other interrelated standards with FAC-003.

[4] The EPR standing review team will grade the standards. The team includes representatives from NERC, the Regions, and the NERC technical committees. Grading will occur prior to conducting the EPR. If there is a change in the standard due to EPR recommendations and subject to the standards development process, the EPR standing review team will re-grade the standard with the revised language.

2016 Progress Report

FERC Directives

As of June 30, 2016, there are 31 outstanding FERC directives.[5] FERC issued some directives pertaining to groups outside of NERC Standards, such as the NERC technical committees and other NERC departments (e.g., topics related to reliability assessment, performance analysis, etc.), and are not included in this count.

Projects Completed in 2016

The 2016–2018 RSDP identified eight projects initiated in 2016 or continued from 2015. All of the projects listed therein have been completed in 2016 or are planned to be completed in 2016, except for Project 2015-08: Emergency Operations, Project 2015-10: Single Points of Failure TPL-001, and Project 2015-09: System Operating Limits, which are expected to be completed in 2017.

The following projects have been or will be completed in 2016:

Projects from the 2016–2018 RSDP

1. Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities
2. Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)
3. Project 2010-07.1 Vegetation Management
4. Project 2010-14.2.1: Phase 2 of Balancing Authority Reliability-based Controls (BAL-005-1, BAL-006-2)
5. Project 2010-14.2.2: Phase 2 of Balancing Authority Reliability-based Controls (BAL-004-2)
6. Project 2015-07 Internal Communications Capabilities

[5] These directives include FERC considerations for future standards development.

2017 Projects

Projects Continuing from 2016 into 2017

The approach to prioritizing Reliability Standards projects in this RSDP is consistent with previous RSDPs. Specific elements include: (1) RISC Category Rankings; (2) regulatory directives and deadlines; (3) Reliability Standard requirements recommended for retirement; (4) the IERP content and quality assessments; and (5) additional considerations (fill-in-the-blank status and five-year assessment commitments). The prioritization considers RISC category rankings, regulatory directives, and regulatory deadlines. Based on the application of these elements, this section prioritizes each Reliability Standard project as high, medium, low, or pending technical committee input.

High Priority

- Project 2013-03 Geomagnetic Disturbance Mitigation
  - ▪ This project will develop reliability standards to mitigate the risk of instability, uncontrolled separation, and Cascading as a result of geomagnetic disturbances (GMDs) through application of Operating Procedures and strategies that address potential impacts identified in a registered entity's assessment as directed in FERC Order 779 and FERC Order No. 830.
    - o From FERC Order No. 830:
      - – Modify the benchmark GMD event definition used for GMD Vulnerability Assessments;
      - – Make related modifications to requirements pertaining to transformer thermal impact assessments;
      - – Require collection of GMD-related data. NERC is directed to make data available; and
      - – Require deadlines for Corrective Action Plans (CAPs) and GMD mitigating actions.
      - – The new standard or modified standard(s) must be with regulatory authorities by May 2018.
- Project 2015-10: Single Points of Failure TPL-001
  - ▪ This project will address two directives and consider other improvements to TPL-001-4 — Transmission System Planning Performance Requirements. There are no remaining time-sensitive directives.
    - o From FERC Order No. 786
      - – Paragraph 40 directs NERC to modify Reliability Standard TPL-001-4 to address the concern that the six-month threshold could exclude planned maintenance outages of significant facilities from future planning assessments.
      - – Paragraph 89 directs NERC to consider a similar spare equipment strategy for stability analysis upon the next review cycle of Reliability Standard TPL-001-4.
  - ▪ RISC: overall risk priority is moderate for protection system and single points of failure (risk profile #3B).
  - ▪ IERP considerations: minor quality and content on possible P81 candidates.
- Project 2016-01: Modifications to TOP and IRO Standards
  - ▪ Modifications to the TOP and IRO standards developed in this project address reliability concerns identified in FERC Order No. 817 as described below.
    - o From FERC Order No. 817:

   - Paragraph 35 directs NERC to revise Reliability Standard TOP-001-3, Requirement R10 to require real-time monitoring of non-BES facilities. We believe this is best accomplished by adopting language similar to Reliability Standard IRO-002-4, Requirement R3, which requires Reliability Coordinators to monitor non-bulk electric system facilities to the extent necessary.
   - Paragraph 47 directs NERC to modify Reliability Standards TOP-001-3, Requirements R19 and R20 to include the requirement that the data exchange capabilities of the Transmission Operators and Balancing Authorities require redundancy and diverse routing.
   - Paragraph 47 directs NERC to clarify that "redundant infrastructure" for system monitoring in Reliability Standards IRO-002-4, Requirement R4 is equivalent to redundant and diversely routed data exchange capabilities.
   - Paragraph 51 directs NERC to develop a modification to the TOP and IRO standards that addresses a data exchange capability testing framework for the data exchange capabilities used in the primary control centers to test the alternate or less frequently used data exchange capabilities of the Reliability Coordinator, Transmission Operator and Balancing Authority.
 - RISC: overall risk priority is moderate for the loss of situational awareness (Risk Profile #3C).
 - IERP considerations: minor quality and content on possible P81 candidates.

- Project 2016-02: Modifications to CIP Standards
  - This project will modify the CIP family of standards to address issues identified by the CIP V5 Transition Advisory Group, FERC directives contained in Order 822 as explained below; and requests for interpretations.
    - From FERC Order No. 822:
      - Paragraph 32 directs that NERC, pursuant to section 215(d)(5) of the FPA, develop modifications to the CIP Reliability Standards to provide mandatory protection for transient devices used at Low Impact BES Cyber Systems based on the risk posed to bulk electric system reliability. While NERC has flexibility in the manner in which it addresses the Commission's concerns, the proposed modifications should be designed to effectively address the risks posed by transient devices to Low Impact BES Cyber Systems in a manner that is consistent with the risk-based approach reflected in the CIP version 5 Standards.
      - Paragraph 53 directs that NERC, pursuant to section 215(d)(5) of the FPA, develop modifications to the CIP Reliability Standards to require responsible entities to implement controls to protect, at a minimum, communication links and sensitive bulk electric system data communicated between bulk electric system Control Centers in a manner that is appropriately tailored to address the risks posed to the bulk electric system by the assets being protected (i.e., high, medium, or low impact).
      - Paragraph 64 directs NERC to conduct a study that assesses the effectiveness of the CIP version 5 remote access controls, the risks posed by remote access-related threats and vulnerabilities, and appropriate mitigating controls for any identified risks. NERC should consult with Commission staff to determine the general contents of the directed report. We direct NERC to submit a report on the above outlined study within one year of the implementation of the CIP version 5 Standards for High and Medium Impact BES Cyber Systems.
      - Paragraph 73 directs NERC to develop a modification to provide the needed clarity, within one year of the effective date of this Final Rule. We agree with NERC and other commenters

that a suitable means to address our concern is to modify the Low Impact External Routable Connectivity definition consistent with the commentary in the Guidelines and Technical Basis section of CIP-003-6.

- RISC: overall risk priority is high for cyber security vulnerabilities (risk profile #4A).
- IERP considerations: not addressed, as they require specialized expertise.

- Project 2016-03 Cyber Security Supply Chain Management
  - This project will address directives from FERC Order No. 829 to develop a new or modified standard to address supply chain risk management for industrial control system hardware, software, and computing and networking services associated with bulk electric system operations. The project will propose a new standard or revisions to approved CIP standards.
    - From FERC Order No. 829:
      - Paragraph 3 directs that NERC develop a forward-looking, objective-based Reliability Standard to require each affected entity to develop and implement a plan that includes security controls for supply chain management for industrial control system hardware, software, and services associated with bulk electric system operations.
      - The new or modified Reliability Standard should address the following security objectives:
        - (1) software integrity and authenticity;
        - (2) vendor remote access;
        - (3) information system planning; and
        - (4) vendor risk management and procurement controls.
      - The new standard or modified standard(s) must be filed with regulatory authorities within one year of the Order No 829 effective date.

Medium Priority

- Project 2015-08: Emergency Operations
  - No FERC directives (FERC guidance has been provided to this project)
  - RISC : medium-priority area (coordinated attack on multiple facilities), low-priority areas (extreme weather/acts of nature)
- RISC: medium-priority area (coordinated attack on multiple facilities), low-priority areas (extreme weather/acts of nature)
  - IERP considerations: minor quality and content on possible P81 candidates
- Project 2015-09: System Operating Limits
  - No FERC directives
  - RISC: high-priority area (Situational Awareness)
  - IERP considerations: minor quality and content on possible P81 candidates
- 2016-EPR-01: Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards - PER-001, PER-003, PER-004
- 2016-EPR-02: Enhanced Periodic Review of Voltage and Reactive Standards - VAR-001, VAR-002

Medium to Low Priority

The following requests for interpretation have commenced in 2016:

- Project 2015-INT-01: Interpretation of CIP-002-5.1 for EnergySec
- Project 2015-INT-03: Interpretation of TOP-002-2.1b for FMPP

Projects Commencing in 2017

The following projects should commence in 2017. Not all projects have SARs, which will be developed and presented to the Standards Committee at the appropriate time to initiate the project.

- At least two EPRs that may recommend revisions to standards.
- Emerging risks, if any, with input from the RISC on whether a standard is needed.
- Potential modifications to existing standards that respond to FERC directives.

Standards Cost Effectiveness Pilot

Federal, state, and provincial regulatory authorities, the NERC Board of Trustees, Regional Entities, and many industry stakeholders have expressed interest in identifying the costs incurred from implementing NERC Reliability Standards compared to risks addressed. The desire is to balance costs and risks during the standards development and revision process. Therefore, in 2016 NERC developed and implemented Phase 1 of its Standards Cost Effectiveness Pilot to inform the Project 2015-10: Single Points of Failure TPL-001 drafting team on potential implementation costs.[6] Phase 2 of the pilot is expected to be completed in 2016 or 2017.

Enhanced Periodic Reviews

Periodic reviews provide a wide view of the standards to determine whether a particular group of standards is effective. Attachment 1 to the RSDP contains the “Enhanced Periodic Review Guidelines” that further explain standards prioritization and selection criteria.

The following EPRs commenced in 2016:

- PER-001, PER-003, and PER-004
- VAR-001 and VAR-002

The following EPRs are eligible to commence in 2017.[7] At least two EPRs will commence in 2017 selected from the following set of eligible standards:

- BAL and INT families of standards (BAL-001, INT-004, INT-006, INT-009, and INT-010)
- EOP-010
- FAC-003-4
- FAC-008-3
- NUC-001-3
- PRC family of standards (PRC-004-5(i), PRC-005-6, PRC-006-2, PRC-010-2, PRC-018-1, PRC-019-2, PRC-023-4, PRC-024-2, PRC-025-1, and PRC-026-1)

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[6] Please see the Cost Effectiveness Pilot web page at http://www.nerc.com/pa/Stand/Pages/CostEffectivenessPilot.aspx for additional information on this initiative.

[7] For reference, the following standards will be eligible for EPRs in 2018 and 2019: EOP-011-1, BAL-003-1.1, COM-001-2.1, COM-002-4, FAC-001-2, FAC-002-2, IRO-009-2, MOD-032-1, MOD-031-2, and TPL-001-4.

Standards Grading Metric

In 2016, NERC implemented a standards grading metric to grade all standards eligible for an EPR, which requires that the standard be in effect in the United States (compliance enforcement date) for at least one year. The EPR standing review team grades the standards using an enhanced version of the IERP grading template. Standards grades are harmonized in public meetings with the initial EPR standing review team grades posted for stakeholder comment. After consideration of comments, the EPR standing review team finalizes the grades and provides the results to the EPR teams, which are comprised of the standing review team and industry subject matter experts tasked with implementing the EPR to completion. Final grades are included as Attachment 2 for informational purposes. The grading will also assist in prioritizing future EPRs. For example, if the grading indicates a gap or a significant need to increase the quality or content of a standard or standard family, that set of standards may have a higher priority over standards and standard families that have high quality and content grades. If an EPR recommendation results in a revised standard, that standard will be re-graded, and the new grade will be attached to a future RSDP for informational purposes.

In 2017, the grading metric will be applied to the standards that are eligible for an EPR to start in 2017, time and resources permitting. In 2017, the grading will occur in the first half of the year, which will assist in the prioritizing of EPRs in 2017 and 2018.

The following non-CIP standards become eligible for standards grading in 2017:[8]

- BAL-003-1.1
- COM-001-2.1
- COM-002-4
- FAC-001-2
- FAC-002-2
- IRO-009-2
- MOD-032-1
- TPL-001-4

In 2018, the TOP and IRO families of standards would be eligible for grading and EPR.

Interpretations

Pursuant to section 7 of the NERC Standard Processes Manual (SPM), the Standards Committee may accept requests for interpretation in 2016 and beyond. Those requests would commence based on NERC and the Standards Committee prioritization, which would also consider timing to ensure projects are developed at a measurable and sustainable pace, consistent with the criteria to prioritize standard projects that are included in this list.

Feedback Loops (Factors for Consideration of Risk)

The following feedback loops, or factors for consideration, will assist in keeping the workload steady by prioritizing (a) the projects that do not have a one-year deadline, and (b) compliance input built earlier into the project's timeline. Projects with a deadline are based on FERC directives that have a filing due date specific in a Final Rule.

[8] For reference, in 2018 the TOP and IRO families of standards will be eligible for standards grading and EPR.

Compliance Monitoring and Enforcement Program Feedback

Compliance Monitoring and Enforcement Program (CMEP) feedback is an available mechanism for ERO Enterprise CMEP staff and registered entities subject to the CMEP activities to provide feedback on a standard, which could be beneficial to identify issues with standards. During CMEP activities, that feedback could be valuable for instructing standards development activity.

The ERO CMEP Implementation Plan is the annual operating plan carried out by Compliance Enforcement Authorities while performing their responsibilities and duties as called for in the CMEP. It prioritizes risks to the Bulk Electric System (BES), registered entity functions, and Reliability Standards based on risk to determine appropriate oversight focus. The results of that plan also help shape prioritizing standards development projects, including EPRs.

ERO Enforcement staff is collecting impact data to determine whether a particular violation caused or contributed to some observed impact on reliability. Data of this kind can further inform standards development by identifying the most consequential requirements, particularly in the context of EPRs.

Implementation Guidance promotes a common understanding between industry and CMEP staff by providing examples for implementing a standard. For many standards, this is straightforward. For others, a variety of approaches may achieve the same objective. The fact that there is significant Implementation Guidance by itself may or may not mean there is reason for changing a standard. For example, the standard language may be clear but have many complicated ways of achieving compliance. Nonetheless, Implementation Guidance is another important feedback mechanism to alert drafting teams of possible ambiguities or complexities during standards development.

Construct of Standards

The IERP recommendations on a new construct of standards will need to be consulted with industry to establish the benefit of realigning the standards. For example, the total transfer capability standards (proposed MOD-001-2) and some of the FAC standards have some overlap. If there is consensus in the industry, a discussion about the standards alignment and where requirements could best reside can take place as part of the EPR discussion.

Coordination with the North American Energy Standards Board (NAESB)

NERC routinely coordinates with NAESB on NERC Reliability Standard development and how it may affect some of the NAESB business practices. NAESB monitors various NERC projects and the coordination between NERC and NAESB will continue.

Emerging Risks and Changing Technologies

The RISC, Integration of Variable Generation Task Force, and ERSWG are three important committees and task forces that focus on emerging risks and changing technologies. They need to be involved during the beginning of 2017 to assist in the EPR for prioritization and technical expertise.

Event Analysis and Compliance Violation Statistics

Event analysis and compliance violation statistics should be reviewed as the EPRs get underway. Lessons learned and statistics from analyzing events will allow teams to review existing requirements to see if there is any correlation between the events and requirements. Violations statistics allow teams to investigate requirements that are highly violated to identify areas where language may have been misinterpreted and provide training to the industry on the intent of the requirements.

Lessons Learned and Frequently Asked Questions

Lessons learned documents are designed to convey information from NERC's various implementation activities. They are not intended to establish new requirements under NERC's Reliability Standards, to modify the requirements in any existing Reliability Standards, nor to provide an interpretation under section 7 of the SPM.

Additionally, there may be other legitimate ways to fulfill the obligations of the requirements that are not expressed in these supporting documents. Compliance will continue to be determined based on the language in the NERC Reliability Standards as amended from time to time. Implementation of a lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

Frequently asked questions (FAQs) provide transparency in providing answers to questions asked by entities. The information presented in FAQ documents is intended to provide guidance and is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing Reliability Standards.

A standard being the subject of numerous lessons learned or FAQs is an indication that the language in the standard may be ambiguous, subject to multiple interpretations, or does not appropriately capture the reliability risk.

Measures

There have been more requests for guidance to industry on expectations for measuring performance on standard requirements. This is evidence that the measures within some standards may not be sufficiently informative. The EPRs should include consideration of requests for guidance from industry, and the efforts should have an emphasis on improving measures such that guidance documents or detailed reliability standard audit worksheets (RSAWs) are not necessary and the measures are sufficient guidance to the industry.

Rationale and Guidelines

Industry feedback will be encouraged on how these sections relate to the work of the Member Representative Committee's compliance guidance work.

Regional Variances

If a regional standard is in effect, or is under consideration for a standards development project, it should be incorporated into continent-wide Reliability Standards as a regional variance in cases where there is a continent-wide standard that addresses the same subject.

Request for Interpretations

Similar to lessons learned and FAQs, a standard receiving a valid interpretation request may indicate problems with the language of the standard or of a requirement.

RSAW Development

In the beginning of 2013, NERC endeavored to develop RSAWs concurrently with standards. The purpose was to post RSAWs within 15 days of a standard posting date to allow the industry to consider the compliance approach from auditors as they vote on the standard(s) being balloted.

Standard Authorization Requests

SARs are an important mechanism for sponsors to transmit standards information to NERC. For example, SARs submitted either by a Registered Entity or Regional Entity after conducting an Inherent Risk Assessment may identify requirements that should be modified to mitigate an emerging reliability risk, or are little to no risk to the BES and should be considered for retirement.

Surveys and Polls

Surveys and polls could be good outreach tools as the feedback loops are implemented in the beginning of 2017. Questions for the industry or thoughts on conducting the EPRs could be an efficient way to collect stakeholder opinions, since standards development is on a more measured and deliberate pace compared to previous years. Therefore, industry feedback is critical to ensure projects and EPRs are appropriately prioritized to focus on high-risk areas.

Attachment 1

Enhanced Periodic Review Guidelines[9]

Developing the plan to conduct EPRs considers several factors. The first task is determining how to group standards for review. For example, it may be reasonable to review standards by looking at the entire standards family, but it may also make sense to look at reliability actions that cut across standard families or by sections of standards that relate to each other.[10]

The next task is determining whether the subject group of standards is eligible for review. Other ongoing or planned standards development projects may affect standards eligibility. Standards are then grouped and prioritized.

Standards Eligibility

The criteria below determine standard eligibility to conduct the EPRs for standards for 2017, 2018, and 2019.

Criteria for What Makes a Standard Eligible:

- All requirements of a Reliability Standard must have been in effect, based on the implementation/compliance dates approved by the applicable governmental authority, for at least a year. In some instances, a standard may be eligible if it has been a year since the effective date of the order[11] approving that standard if entities are "early adopting" the requirements as they implement their programs to prepare for the effective date. Examples of standards that met this criterion for the initial 2016 EPRs were:
  - NUC-001-3 and NUC-001-2.1: NUC-001-2.1 was effective 4/1/2013 and NUC-001-3 was effective 1/1/2016. The changes in NUC-001-3 were not significant (e.g., they related to capitalization of terms, deleting unneeded terms, etc.).
- Compliance expectations are not clear or the standard is not being consistently monitored.
- Feedback loops indicate risk (e.g., Event Analysis lessons learned).

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[9] Per Section 13 of the SPM, 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 NERC Board of Trustees adoption to a revision of the Reliability Standard, whichever is later. If a Reliability Standard is approved by the American National Standards Institute 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 NERC Board of Trustees adoption to a revision of the Reliability Standard, whichever is later.

The RSDP 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 an issue that needs resolved, then the Reliability Standards Development Plan shall include a project for the complete review and associated revision of the Reliability Standard. This 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 the Reliability Standard, then the RSDP shall include a project solely for the "five-year review" of that Reliability Standard.

While the main work in the next three years will be the continuation of research and conducting of the enhanced periodic reviews with consideration of the topics discussed below, there may be risks identified for which projects may need to be initiated.

[10] The IERP developed one approach to grouping standards.

[11] "Effective date" and "issue date" are different, so this must be considered.

- Outstanding Paragraph 81 requirements that may not have been addressed.
- The implementation of the *Standards Independent Experts Review Project - Final Report* recommendations.[12]
- Per the SPM, standards will go through a review at least once every 10 years for non-American National Standards Institute (ANSI) approved standards and every five years for ANSI-approved standards.

Criteria for What Makes a Standard Not Eligible:

- A standard that is part of a current standards development project or is scheduled for standards development that will likely result in significant revisions of the standard currently in effect.
  - Standards development here includes standards:
    - in a standards development project;
    - adopted by the NERC Board of Trustees;
    - pending regulatory filing;
    - filed with regulatory agencies; or
    - approved by regulatory agencies but not yet in effect.

Prioritization

Specific elements considered in the prioritization of the EPRs include:

1. RISC category rankings
2. Feedback on risk through a risk-based input mechanism
3. Outstanding regulatory directives with deadlines
4. Outstanding regulatory directives
5. Outstanding requirements that are candidates for retirement
6. The grading of Standards developed by the Standing Review Team, including the final grades set forth in Attachment 2 and any additional final grades developed and finalized in any given year
7. *Standards Independent Experts Review Panel - Final Report* content and quality assessments

[12] The Standards IERP final report recommendations can be found here: http://www.nerc.com/pa/Stand/Standards%20Development%20Plan%20Library/Standards_Independent_Experts_Review_Project_Report.pdf

Attachment 2

Final Grades for Standards Graded in 2016

The Enhanced Periodic Review (EPR) Standing Review Team (SRT) was tasked with using metrics from the 2013 Independent Experts Review Panel to assign numeric grades to instruct future EPR teams. While the SRT's final standards grades are important data points for the EPRs to consider, they are intended as one of many inputs to facilitate discussion during the reviews.

The EPRSRT completed the initial grading of eligible Reliability Standards, which NERC posted for a 30-day stakeholder comment period. The EPR SRT conducted a second public meeting in which it considered input from stakeholders and held additional discussion prior to reaching consensus to finalize the grades. Shown below are the average SRT grades for content (0-3) and quality (0-12) for each of the standard requirements eligible for EPR in 2016-2017. Detailed analysis and background information on the Standards Grading process can be found on the project page.

Standard and Requirement	Content Average	Quality Average
BAL-001-2 , R1	3.00	11.5
BAL-001-2 , R2	3.00	11
EOP-010-1, R1	3.00	12
EOP-010-1, R2	2.67	10
EOP-010-1, R3.	3.00	11.75
EOP-011-1, R1.	3.00	11.5
EOP-011-1, R2.	3.00	12
EOP-011-1, R3.	2.50	10.75
EOP-011-1, R4.	2.50	11
EOP-011-1, R5.	2.75	11.75
EOP-011-1, R6.	2.75	11.5
FAC-008-3, R1	3.00	10.75
FAC-008-3, R2.	3.00	11.33333
FAC-008-3, R3.	3.00	11.5
FAC-008-3, R6.	3.00	11
FAC-008-3, R7.	2.50	10.5
FAC-008-3, R8.	2.75	10.25
INT-004-3.1, R3.	3.00	11.25
INT-006-4, R1	3.00	11
INT-006-4, R2	3.00	11.25
INT-006-4, R3.	3.00	11.5
INT-006-4, R4	3.00	11.25
INT-006-4, R5	3.00	11.75
INT-009-2.1, R1	3.00	11.5
INT-009-2.1, R2	3.00	12

Standard and Requirement	Content Average	Quality Average
INT-009-2.1, R3.	3.00	12
INT-010-2.1, R1	3.00	11
INT-010-2.1, R2	3.00	11.5
INT-010-2.1, R3.	3.00	11
NUC-001-3, R1	3.00	12
NUC-001-3, R2.	3.00	12
NUC-001-3, R3.	2.75	12
NUC-001-3, R4.	3.00	11.75
NUC-001-3, R5.	3.00	12
NUC-001-3, R6.	3.00	12
NUC-001-3, R7.	3.00	12
NUC-001-3, R8.	3.00	12
NUC-001-3, R9	3.00	11.75
PER-003-1, R1.	3.00	11.5
PER-003-1, R2.	3.00	11.5
PER-003-1, R3.	3.00	11.5
PER-004-2, R1.	2.75	11.25
PER-004-2, R2.	3.00	9.5
PRC-004-5(i), R1.	2.75	11.75
PRC-004-5(i), R2.	3.00	11.75
PRC-004-5(i), R3.	3.00	11.25
PRC-004-5(i), R4.	3.00	11.5
PRC-004-5(i), R5.	3.00	11.5
PRC-004-5(i), R6.	3.00	11.5
PRC-005-6, R1.	2.75	11.25

Standard and Requirement	Content Average	Quality Average
PRC-005-6, R2.	3.00	11.5
PRC-005-6, R3.	3.00	11.5
PRC-005-6, R4.	3.00	11.5
PRC-005-6, R5.	2.75	10.5
PRC-006-2, R1.	3.00	11.5
PRC-006- , R11.	3.00	12
PRC-006-2, R12.	3.00	11.75
PRC-006-2, R13.	3.00	12
PRC-006-2, R2.	2.00	11.5
PRC-006-2, R3.	3.00	11.5
PRC-006-2, R4.	3.00	11.75
PRC-006-2, R5.	3.00	11.75
PRC-006-2, R6.	3.00	11.75
PRC-006-2, R7.	3.00	12
PRC-006-2, R8.	3.00	11.75
PRC-006-2, R9.	3.00	11.5
PRC-010-2, R1.	2.50	11.5
PRC-010-2, R2.	3.00	11.5
PRC-010-2, R3.	2.50	11.25
PRC-010-2, R4.	2.50	12
PRC-010-2, R5.	2.50	12
PRC-010-2, R6.	3.00	11.5
PRC-010-2, R7.	3.00	12
PRC-010-2, R8.	3.00	12
PRC-019-2, R1.	3.00	11.75

Standard and Requirement	Content Average	Quality Average
PRC-019-2, R2.	3.00	11.75
PRC-023-4, R1.	3.00	11.25
PRC-023-4, R2.	2.75	11.25
PRC-023-4, R3.	2.75	11.75
PRC-023-4, R4.	2.75	11.5
PRC-023-4, R5.	3.00	11.25
PRC-023-4, R6.	3.00	11.75
PRC-024-2, R1.	3.00	11.75
PRC-024-2, R2.	3.00	11.75
PRC-024-2, R3.	3.00	11.5
PRC-024-2, R4.	3.00	11.75
PRC-025-1, R1.	2.75	11.5
VAR-001-4.1, R1.	3.00	11.25
VAR-001-4.1, R2.	3.00	11.25
VAR-001-4.1, R3.	3.00	11.5
VAR-001-4.1, R4.	3.00	11
VAR-001-4.1, R5.	3.00	11.75
VAR-001-4.1, R6.	2.75	11.75
VAR-002-4, R1.	3.00	11.25
VAR-002-4, R2.	3.00	12
VAR-002-4, R3.	3.00	12
VAR-002-4, R4.	3.00	11.5
VAR-002-4, R5.	3.00	12
VAR-002-4, R6.	3.00	11.25

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RR15-2-000**

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION'S ANNUAL COMPLIANCE MONITORING AND ENFORCEMENT PROGRAM FILING

February 21, 2017

<u>**TABLE OF CONTENTS**</u>

I. INTRODUCTION

The North American Electric Reliability Corporation (NERC) respectfully submits this filing in accordance with the Federal Energy Regulatory Commission's (FERC or the Commission) February 19, 2015, *Order on Electric Reliability Organization Reliability Assurance Initiative and Requiring Compliance Filing*[1] and its November 4, 2015, *Order Conditionally Accepting Compliance Filings*.[2]

In 2016, NERC and the eight Regional Entities continued to implement the risk-based Compliance Monitoring and Enforcement Program (CMEP). The attached 2016 CMEP Annual Report reviews the progress of the program and describes the key activities that occurred in 2016. NERC submits the 2016 CMEP Annual Report on an information basis. In addition, NERC is proposing certain enhancements to specific portions of the risk-based CMEP based on the Electric Reliability Organization (ERO)[3] Enterprise's[4] experience with the implementation of these programs over the past year.

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[1] *North American Electric Reliability Corp.*, 150 FERC ¶ 61,108 (2015) (*February 19 Order*). In the *February 19 Order*, the Commission conditionally approved the implementation of the risk-based CMEP, finding that the "overall goal of focusing ERO and industry compliance resources on higher-risk issues that matter more to reliability is reasonable." *Id*. at P 2. The Commission also directed NERC, among other things, to submit an annual informational filing, within one year from the date of the issuance of the order; to review the progress of the risk-based CMEP; and to address a number of other specific topics regarding oversight processes and implementation assessment. *Id*. at PP 32, 42-43, 46, 49-52.

[2] *North American Electric Reliability Corp.*, 153 FERC ¶ 61,130 (2015) (*November 4 Order*). The *November 4 Order* conditionally accepted NERC's May 20 and July 6 compliance filings.

[3] The Commission certified NERC as the ERO in accordance with Section 215 of the Federal Power Act on July 20, 2006. *See North American Electric Reliability Corp.*, 116 FERC ¶ 61,062 (2006), *reh'g denied in part and granted in part*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 342 (D.C. Cir. 2009).

[4] "ERO Enterprise" refers to NERC and the eight Regional Entities.

II. EXECUTIVE SUMMARY

Based on the results of its oversight activities, NERC identified two enhancements to the risk-based CMEP that are proposed herein and further discussed in this filing: (1) providing minimal risk Compliance Exceptions (CEs) identified through self-logging to FERC non-publicly; and (2) expanding the use of CEs to include certain moderate risk noncompliance currently processed through Find, Fix, Track and Report (FFTs).

The ERO Enterprise established the Self-Logging Program to achieve three primary goals: (1) to promote the development of strong internal controls to identify, assess, and correct noncompliance; (2) to enhance the ERO Enterprise's visibility into registered entities' internal controls to identify, assess, and correct minimal risk noncompliance; and (3) to drive processing efficiencies at the ERO Enterprise and the registered entity through a streamlined, nonpublic resolution of minimal risk noncompliance logged by program participants.

When FERC originally approved the Self-Logging Program, it required that the noncompliance logged by registered entities be posted publicly in spreadsheets. This requirement unintentionally removed an incentive for registered entities to participate in the program. That, in turn, appears to have reduced interest in the program and, consequently, reduced the benefits accruing to the ERO Enterprise and program participants of significant program growth. For example, the continued growth of the program would have contributed to the expansion of the ERO Enterprise's visibility into entities' internal controls to identify, assess, and correct noncompliance. The requirement for public posting also has reduced the efficiency benefits associated with the program as participants spend additional time to prepare their logs for public disclosure; and potentially tempered entities inclination to include near misses in logs, limiting the opportunity for the ERO Enterprise and the registered entities to have robust trending discussions prior to issues becoming noncompliance.

In 2016, NERC staff conducted a thorough review of the Self-Logging program and determined that the Regional Entities are admitting the right entities into the program, and logs are accurate and adequate. The additional experience with the program supports recalibrating the program rules to realign them with the original tenets of the program. Additional improvements to the program in the areas of outreach and the evaluation process are also being considered. NERC also plans to solicit further feedback from program participants. The focus of this filing is the public posting of logged noncompliance.

NERC's proposal is to provide self-logged CEs to FERC non-publicly. The Self-Logging Program would remain limited to minimal risk noncompliance. NERC would continue to post non-logged noncompliance pursuant to current processes. In addition, NERC supports continuous learning by all registered entities and understands that some entities may derive a benefit from reviewing that non-public information. Therefore, in connection with its proposal, the ERO Enterprise would make two enhancements to the information it provides publicly. First, it would provide annual summaries of the noncompliance included in the logs in its Annual CMEP Report. Second, NERC would begin posting on its website a public list of registered entities admitted to the Self-Logging Program. This public list of high-performing entities would provide an additional incentive for registered entities to request admission to the program.

As a second enhancement to the risk-based CMEP, NERC is also proposing to expand the CE program to allow for the resolution of certain moderate risk noncompliance. As criteria to determine which moderate risk noncompliance may be eligible for CE treatment, among other things, the Compliance Enforcement Authority (CEA) would consider: (1) the registered entity's internal compliance program, management practices that self-identify noncompliance, and commitment to compliance; (2) mitigating factors during the pendency of the noncompliance; and

(3) "above and beyond" mitigating measures. At this time, NERC would not consider it appropriate to treat as CEs moderate risk noncompliance that have an aggravating compliance history.

The criteria mirror that which FERC approved for moderate risk noncompliance treated as FFTs. After further experience with moderate risk CEs, the ERO Enterprise would consider the continued need for the FFT program.

Any necessary Rules of Procedure changes associated with the two enhancements proposed herein would be developed and submitted to the Commission at a later date.

III. PROPOSED PROGRAM ENHANCEMENTS

In its March 15, 2012 Order accepting the FFT program, the Commission agreed that NERC and the Regional Entities should have the flexibility to process and track lesser risk violations more efficiently in order to focus their attention on issues that pose the greatest risk to reliability.[5] The Commission anticipated that acceptance of NERC's proposal would be "the first step to a more efficient and effective compliance and enforcement process" and as the ERO Enterprise gains more experience with the program, the Commission would consider and evaluate ways to enhance it further.[6] To achieve this goal, NERC has identified two enhancements to the risk-based CMEP to continue the evolution to a more efficient and effective program—providing self-logged instances of noncompliance to FERC non-publicly and including certain moderate risk noncompliance in the CE program. The implementation of these enhancements may require

[5] *North American Electric Reliability Corp.*, 138 FERC ¶ 61,193 at P 3 (2012) (*March 15 Order*).

[6] *Id.*

changes to the NERC Rules of Procedure. NERC will develop and submit proposed revisions to the Rules of Procedure to articulate these changes upon FERC's approval, or as directed by the Commission.

A. NERC Proposes Discontinuing the Public Posting of Self-logged CEs

The Self-Logging Program provides a registered entity found eligible to participate the ability to log minimal risk noncompliance for subsequent review by the CEA in lieu of submitting a Self-Report. Participants are admitted upon a formal review of their internal controls related to their ability to identify, assess, and correct noncompliance. Self-logged items carry a presumption of CE treatment and are processed in a streamlined manner. [7]

In 2016, NERC staff performed a review of the Self-Logging Program to ensure the Regional Entities were properly promoting, implementing, and overseeing use of the program. As part of the process review, NERC staff evaluated how the Regional Entities determined a registered entity's eligibility for acceptance into the Self-Logging Program. NERC staff confirmed there was adequate evidence and information to support each of the registered entities' eligibility for participation in the program. In addition, NERC staff found the Regional Entities are consistently performing formal reviews of registered entities' internal controls for identifying, assessing, correcting, and reporting minimal risk noncompliance. NERC staff found that while each Regional Entity's process to formally review an entity's internal controls was slightly different, tailored to match the needs of that Regional Entity and registered entity, all of the Regional Entities provided

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[7] *See* North American Electric Reliability Corp., *ERO Enterprise Self-Logging Program* 3-4 (Feb. 1, 2016), http://www.nerc.com/pa/comp/Reliability%20Assurance%20Initiative/Updated_ERO%20Enterprise%20Self-Logging%20Program%20(2-1-16).pdf.

evidence their evaluations were consistent with the Self-Logging Program. NERC staff confirmed all Regional Entities assess program applicants by examining internal controls, internal compliance program, and compliance history, including past cooperation and self-assessments.

Encouraging and facilitating registered entity involvement in the Self-Logging Program benefits not only the registered entity itself, with streamlined processing and presumed CE treatment, but also the ERO Enterprise with enhanced transparency and efficient evaluation of registered entity controls and more efficient review and processing of noncompliance. The program also resulted in increased efficiencies when compared to the processing of individual Self-Reports and other minimal risk noncompliance.[8] NERC attributes this efficiency to the Regional Entity's ability to rely on the self-logging registered entities' internal controls that help with the identification, assessment, and correction of the noncompliance correctly and swiftly.

i. The Self-Logging Program as Originally Proposed

The ERO Enterprise originally designed the Self-Logging Program to promote the development and disclosure of internal controls as well as to further streamline processing of noncompliance for entities with effective internal controls.[9] The kinds of behavior the program rewards are those related to internal practices at registered entities relating to self-monitoring, identification, assessment, and correction of noncompliance with Reliability Standards. By

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[8] In 2016, NERC evaluated the processing times of noncompliance from the time the registered entity reported the noncompliance to the Regional Entity to the date NERC posted the noncompliance as a CE. NERC reviewed all the self-logged noncompliance submitted from April 2014 through March 2016 and compared them to the processing times for non-self-logged CEs processed in the same period as the self-logged items. NERC's analysis found the ERO Enterprise processes self-logged noncompliance in nearly one-third the time of CEs discovered through other means.

[9] *North American Electric Reliability Corp.*, Docket No. RR15-2-000, at 53-64 (Dec. 3, 2014) (*NERC RAI Filing*).

appropriately rewarding entities that develop and demonstrate the implementation of strong internal controls, the ERO Enterprise encourages the enhancement of those internal controls and self-identification of noncompliance throughout the industry, and by extension, improves the reliability of the bulk power system (BPS).

The ERO Enterprise intended the Self-Logging Program to achieve three primary goals. First, to promote the development, by registered entities, of strong internal controls to identify, assess, and correct noncompliance by rewarding those entities with a significantly streamlined process and non-public resolution of minimal risk noncompliance. Second, to drive processing efficiencies for both the ERO Enterprise and the registered entity for the resolution of minimal risk noncompliance self-identified by registered entities that possess and employ these demonstrated strong internal controls. Finally, to enhance the ERO Enterprise's visibility into registered entities' internal controls to identify, assess, and correct minimal risk noncompliance, which the ERO Enterprise evaluates in an efficient manner as part of the entity's admission into the program.

A significant incentive for participating in the Self-Logging Program is the presumption of CE treatment for logged noncompliance.[10] Originally, the ERO Enterprise proposed that logged

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[10] CE is a fast-track disposition method with shorter processing times leading to higher efficiency when processing minimal risk noncompliance. CEs receive no financial penalty and do not apply negatively to an entity's compliance history. A CE is part of an entity's compliance history only when "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)." *North American Electric Reliability Corp.*, 150 FERC ¶ 61,108 at P 44 (2015) (*February 19 Order*). Furthermore, prior CEs are considered when "assessing any subsequent noncompliance of the same or closely-related Standards and Requirements to determine whether the registered entity should continue to qualify for [CE] treatment regarding the subject of the repeat noncompliance," but "[such] subsequent noncompliance . . . in and of itself should not disqualify an entity from RAI." *Id.* at P 45.

noncompliance would be resolved non-publicly.[11] The non-public disposition of noncompliance was at once an incentive for participation but also a way to refocus the attention of the public to enforcement actions, which address violations posing greater risk to the BPS.[12]

ii. The Self-Logging Program as Conditionally Approved

FERC's *February 19 Order* approving NERCs implementation of additional components of the risk-based CMEP, including CEs and self-logs, instructed NERC to post the CEs publicly similar to its FFT posting.[13] When the ERO Enterprise first introduced CEs, FERC found that public posting provided the ability to understand and assess the value of the information included in CEs, as well as the success of NERC's oversight of the CE program. FERC's intent in directing that CEs, including those originating from self-logs, be made public was "to educate industry to avoid and mitigate noncompliance with reliability standards, and to maintain the credibility of NERC's compliance and enforcement regime."[14] The proposed Self-Logging Program was new to the ERO Enterprise, so additional oversight at the time was appropriate.

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[11] NERC RAI Filing at 44.

[12] *Incorporating Risk Concepts into the Implementation of Compliance and Enforcement*, NERC Whitepaper No. 1, 9 (November 15, 2012).
http://www.nerc.com/pa/comp/Reliability%20Assurance%20Initiative/Reliability%20Assurance%20Initiative_White%20Paper%20%C3%A2%E2%82%AC%E2%80%9C%20The%20Need%20for%20Change%20(paper%201).pdf

[13] *North American Electric Reliability Corp.*, 150 FERC ¶ 61,108 at PP 26, 36 (2015) (*February 19 Order*).

[14] *See id.* at P 36.

FERC recognized the flexibility inherent in the Self-Logging Program but placed several qualifications on its conditional approval of NERC's proposed implementation.[15] Some of these affected the program positively. For example, FERC's requirement of some level of formal review of an entity's internal controls before granting the flexibility to the entity to self-log instances of noncompliance ensured that only registered entities with proven controls are being rewarded with participation in this program. Similarly, FERC's requirement for a standardization of the content and review of an entity's compliance logs to allow for consistency and ease of compilation and comparison has strengthened the Self-Logging Program.[16]

Nevertheless, the requirement to post self-logged items publicly appears to have limited the incentives for entities participating in the program because it effectively results in treating the processing of self-logs no differently than other lesser risk issues. In fact, NERC's process review determined that nearly all the Regional Entities had received feedback from registered entities that the required public posting of self-logs has led to a lack of continued interest in the Self-Logging Program.

iii. NERC Recommends Non-Public Posting of Self-Logged Noncompliance

As this transition period has passed, NERC has had the opportunity to consider whether the information included in self-logs is "essential to industry education and effective oversight of

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[15] *Id.* at PP 25-43.

[16] *Id.* at P 43.

the enforcement process."[17] Even commenters originally arguing for public disclosure acknowledged that the issue of public provision of noncompliance was appropriate to revisit after two years.[18] Upon assessing the self-logged noncompliance that NERC has posted on its website over the past several years,[19] NERC determined that the educational value the public could derive from the review of individual logged items is limited. Public posting of self-logged noncompliance also potentially diverts the public's attention from the review of higher risk matters which are posted as Notices of Penalty. As noted below, however, NERC is proposing other means of providing an educational benefit to registered entities and the general public in connection with its Annual Reports.

Self-logged noncompliance is subject to oversight by NERC and FERC. NERC and the Regional Entities also use the information obtained from the logs to identify trends and patterns.[20]

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[17] Joint Commenters' Comments at 1-2, *North American Electric Reliability Corp.*, Docket No. RR15-2-000 (Dec. 3, 2014). The "Joint Commenters" were comprised of the American Public Power Association, Electricity Consumers Resource Council, Large Public Power Council, National Rural Electric Cooperative Association, and Transmission Access Policy Group. *See February 19 Order* at P 23.

[18] *See* Joint Commenters at 1-2, 11 ("After that initial [two-year] period, and with the benefit of preferably two RAI annual reports, the Commission, with input from the industry and other stakeholders, can assess whether that level of transparency should be continued.").

[19] In 2016, NERC conducted an analysis of 630 CEs from 2014 and 2015. Fifteen percent of the CEs reviewed were self-logged. In addition, approximately 10% of the CEs reviewed in the 2015 joint FFT/CE review were self-logged. As a part of its 2016 Self-Logging Program review, NERC analyzed an additional 48 self-logged instances of noncompliance, including all supporting documentation. *See* 2016 CMEP Annual Report at 6 and 13.

[20] In addition to the efficiency gains at the Regional Entity and ERO levels, the logs are also an ideal method for trend spotting for specific entities because all minimal risk noncompliance related to a particular entity are contained on the log. Log review and discussion may trigger productive dialogue between the Regional Entity and the registered entity regarding expanding mitigating activities to prevent broader issues in the future. As the registered entity must do its own risk assessment in order to determine whether the noncompliance qualifies for self-logging, and because the rationale contained within the log must support the risk assessment, Regional Entities often see more analysis of risk on the registered entity's part when it comes to noncompliance with Reliability Standards than

As outlined by one commenter in the NERC RAI docket, facilitating documentation and reporting of all noncompliance by registered entities encourages them to report all of their compliance issues.[21] This facilitates full and open communication between a registered entity and its Regional Entity—providing a comprehensive view of risks to reliability in a Regional Entity footprint. Making self-logs non-public encourages broader participation, which as a result amplifies the benefits of the program for the ERO Enterprise and registered entities.[22]

Instead of public posting, NERC staff would include self-logged noncompliance in a separate confidential spreadsheet, in much the way it currently provides the non-redacted CIP CEs to FERC. NERC and the Regional Entities would prepare an anonymized annual summary of self-logged noncompliance that NERC would include in its CMEP Annual Reports. These summaries would describe generally the noncompliance identified in the logs, common themes in root cause and risk, and successful mitigation strategies used to address those causes and risk. NERC anticipates that these summaries would provide more useful information regarding noncompliance, risk, and mitigation than stakeholders would be able to receive from simply listing the individual self-logged CEs as it now does. The annual summaries and targeted lessons learned

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is common in even Self-Reports. This additional data, insight, and facilitation of trend spotting benefit the reliability of the BPS by providing a view of risk in the Regional Entity footprints as well as ERO Enterprise-wide.

[21] *See* Motion to Intervene and Comments of the Midcontinent Independent System Operator, Inc. at p. 5, *North American Electric Reliability Corp.*, Docket No. RR15-2-000 (Dec. 3, 2014).

[22] As discussed, the requirement to publicly post self-logged noncompliance has shifted to some extent the balance of benefits of the program, making it less beneficial to program participants.

would address FERC's concern for similarly situated entities that may find information in the self-logs valuable.

In addition, the ERO Enterprise would begin posting on its website a list of registered entities admitted to the Self-Logging Program. This public list of high-performing entities would provide an additional incentive for registered entities to request admission to the program and provide an additional level of transparency to the public.[23]

Therefore, for the reasons stated above, NERC proposes that it discontinue the public posting of self-logged CEs on the NERC website, while still providing those CEs to FERC non-publicly. Self-logged CE data would still exist non-publicly within the ERO Enterprise and with FERC for oversight and analysis. In addition, as stated above, the ERO Enterprise would produce annual summaries of self-logged instances of noncompliance for public consumption and provide the list of self-logging participants on NERC's enforcement webpage.

B. NERC Proposes Treating Certain Moderate Risk Noncompliance as CEs

In a risk-based approach to enforcement, serious risk violations are always subject to an enforcement action. Moderate and minimal risk noncompliance, however, may be resolved through an enforcement action or a non-enforcement track based on the facts and circumstances.

[23] NERC does not post information on self-logging registered entities because such information could potentially be used to identify Critical Energy Infrastructure Information (CEII) information related to those entities with self-logged noncompliance with CIP Reliability Standards posted on NERC's enforcement webpage. When NERC no longer posts self-logged noncompliance on its webpage, it would no longer need to keep the identity of self-logging participants confidential.

The FFT program was the first major step in implementing a risk-based approach to enforcement of noncompliance with Reliability Standards that recognizes not all instances of noncompliance require the same type of process and documentation. Over the last five years, the success of the FFT program in resolving lesser risk noncompliance led to the development of the CE program for certain minimal risk issues and the expansion of the FFT program to include resolution of moderate risk issues.[24] As detailed in the attached 2016 CMEP Annual Report, the ERO Enterprise now uses these programs to resolve more than half of discovered noncompliance.[25]

While these streamlined disposition methods allow the ERO Enterprise to process minimal and moderate risk issues more efficiently, focus on issues posing a higher risk to reliability, reduce administrative burdens, and continue to encourage self-reporting and mitigation, the ERO Enterprise's ability to resolve noncompliance outside of an enforcement track currently is limited to minimal risk noncompliance.

In its 2014 filing, NERC indicated it would consider the inclusion of moderate risk issues as CEs in the future.[26] The implementation of the CE program has been successful, as noted in

[24] *See* Annual Report of the North American Electric Reliability Corp. on the 2016 ERO Enterprise Compliance Monitoring and Enforcement Program at 22, *North American Electric Reliability Corp.*, Docket No. RC11-6-000 (Feb. 8, 2017) (2016 CMEP Annual Report); *see also* Annual Report of the North American Electric Reliability Corp. on the Find, Fix, Track and Report and Compliance Exception Programs, *North American Electric Reliability Corp.*, Docket No. RC11-6-000 (Nov. 14, 2016); *North American Electric Reliability Corp.*, Notice of Staff Review of Compliance Programs, Docket No. RC11-6-004 (FERC June 15, 2016).

[25] 2016 CMEP Annual Report at 29

[26] NERC RAI Filing at 46.

the most recent evaluations by NERC[27] and in the 2016 CMEP Annual Report. Including certain moderate risk noncompliance as CEs would be the next logical step in the evolution of the program.[28]

In order to use the CE program efficiently in connection with moderate risk noncompliance, NERC is proposing criteria to determine which moderate risk noncompliance would be eligible for CE treatment, which is similar to the criteria approved by the Commission for processing moderate risk noncompliance through the FFT program.[29] The criteria would facilitate acknowledgment by the ERO Enterprise of registered entities with strong management practices that self-identify noncompliance. They would also provide clear incentives for other registered entities to self-report and strengthen their management practices.

When determining whether to process a moderate risk noncompliance as a CE or in a Notice of Penalty (NOP), the Regional Entity would focus on the underlying facts and circumstances of the noncompliance, including what happened, why, where, and when. Another factor Regional Entities would use to determine whether a noncompliance should be eligible for CE treatment is the level of risk to reliability, including mitigating factors during the pendency of the noncompliance. Regional Entities consider the registered entity's internal compliance program, including preventive and corrective processes and procedures, management practices, and culture of compliance as factors to help determine whether a noncompliance should receive

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[27] *See* Annual Report of the North American Electric Reliability Corp. on the Find, Fix, Track and Report and Compliance Exception Programs. *North American Electric Reliability Corp.*, Docket No. RC11-6-000 (2016).

[28] After realigning the range of tools with the risk a noncompliance posed to reliability, the ERO Enterprise would consider whether ongoing use of other tools such as the FFT continue to be necessary.

[29] *North American Electric Reliability Corporation*, 143 FERC ¶ 61,253 (2013).

CE treatment. A robust program, with strong management practices around Reliability Standards that led to timely discovery and swift mitigation of noncompliance, creates a strong argument in favor of CE treatment. Regional Entities would also consider the presence and applicability of aggravating factors, such as repeat noncompliance. At this time, NERC would not consider it appropriate to treat moderate risk noncompliance that have an aggravating compliance history as CEs. While prior noncompliance that may have been processed as a CE is not considered aggravating for penalty purposes, the ERO Enterprise would continue to consider them as a part of a registered entity's risk profile. Prior minimal risk CEs showing same or similar conduct may be an indicator of an entity's inability to institute effective mitigation and remediation. A moderate risk noncompliance that does not qualify for CE treatment may still be eligible for zero dollar streamlined enforcement (i.e. Spreadsheet NOP) treatment despite an aggravating compliance history if the registered entity has a strong compliance culture, with robust self-reporting, or other mitigating factors are present.

Each enhancement to the risk-based CMEP aligns the program with the ERO Enterprise's envisioned end-state.[30] This end-state for risk-based enforcement requires the flexibility of a range of tools to prioritize and treat noncompliance based on risk and enforcement practices with clear distinctions based on risk posed to the reliability of the BPS. Aligning the disposition of noncompliance to the risk posed by that noncompliance will provide more meaningful and streamlined signals about identified areas of concern and risk prioritization. The criteria for

[30] *Incorporating Risk Concepts into the Implementation of Compliance and Enforcement*, NERC Whitepaper No. 1, 9 (2012). http://www.nerc.com/pa/comp/Reliability%20Assurance%20Initiative/Reliability%20Assurance%20Initiative_White%20Paper%20%C3%A2%E2%82%AC%E2%80%9C%20The%20Need%20for%20Change%20(paper%201).pdf.

moderate risk CEs mirror that which FERC approved for moderate risk FFTs. Therefore, after further experience with moderate risk CEs, the ERO Enterprise would consider the continued need for the FFT program.

IV. CONCLUSION

NERC respectfully requests that the Commission accept this report in compliance with the February 19 and November 4 Orders, and approve the proposed program enhancements requested herein.

Respectfully submitted,

/s/ Leigh Faugust

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Counsel for the North American Electric Reliability Corporation

Dated: February 21, 2017

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 Docket No. RR15-2-000.

Dated at Washington, D.C. this 21st day of February, 2017.

Respectfully submitted,

/s/ Leigh Faugust

Counsel for the North American Electric Reliability Corporation

ATTACHMENT

2016 ERO Enterprise CMEP Annual Report

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2016 ERO Enterprise Compliance Monitoring and Enforcement Program Annual Report

February 8, 2017

RELIABILITY | ACCOUNTABILITY

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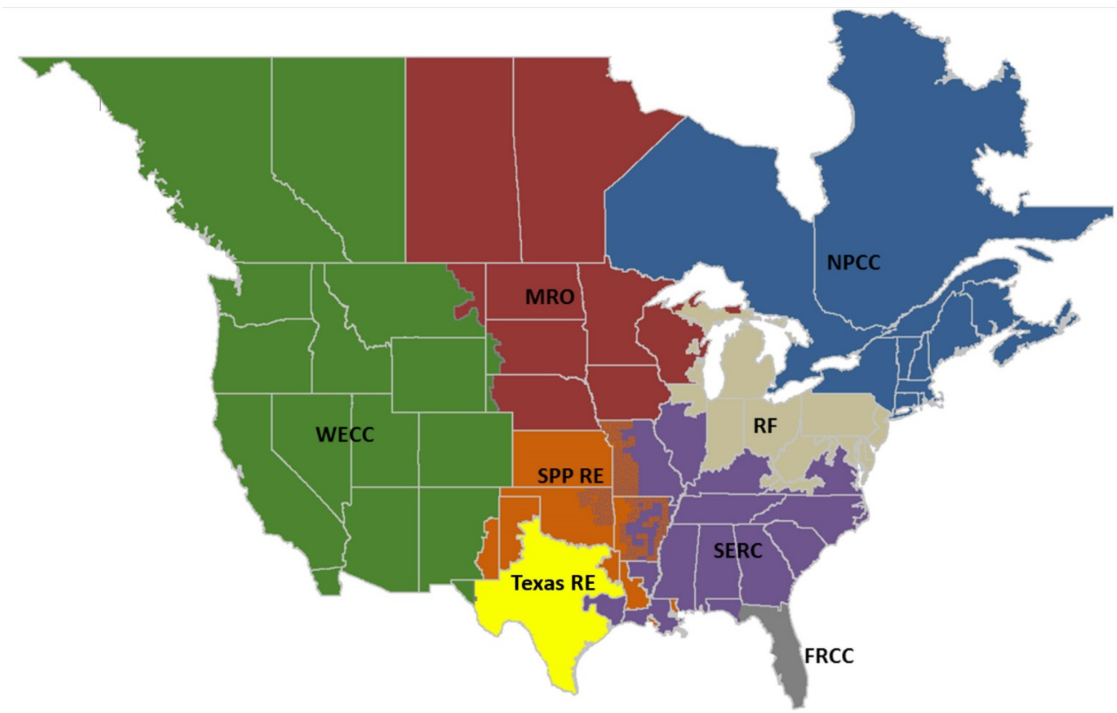
Table of Contents

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 Entity (RE) boundaries as shown in the map and corresponding table below.



The North American BPS is divided into eight RE boundaries. The highlighted areas denote overlap as some load-serving registered entities participate in one region while associated transmission owners or operators participate in another.

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

Executive Summary

This report highlights key ERO Enterprise[1] Compliance Monitoring and Enforcement Program (CMEP) activities that occurred in 2016, provides information and statistics regarding those activities, and identifies the ERO Enterprise's 2017 CMEP priorities. In 2016, CMEP activities throughout the ERO Enterprise reflected continuing implementation of the risk-based approach introduced in 2013 through the Reliability Assurance Initiative. Most significantly, ERO Enterprise and industry compliance and enforcement resources were focused on risks to the BPS, entity-specific risks, and serious risk noncompliance in 2016. The ERO Enterprise also continued its commitment to align core CMEP activities. The following is a brief overview of these activities, which are discussed in greater detail throughout this report.

Risk-based CMEP Activities

In 2016, the ERO Enterprise reviewed lessons learned from risk-based CMEP implementation and identified opportunities for refinement. In particular, the ERO Enterprise compliance activities focused on aligning Inherent Risk Assessment (IRA) processes across the ERO Enterprise. The IRA is a review of inherent risks posed by an individual registered entity to BPS reliability and is one of the core components of the risk-based CMEP framework. In addition, the ERO Enterprise reviewed opportunities for alignment in approaches to internal controls and Compliance Oversight Plans (COPs). Outputs of these reviews included a refined set of risk factors, the ERO Enterprise Guide for Compliance Monitoring, and the ERO Enterprise Guide for Internal Controls. The results of these efforts represent a significant step toward ensuring consistency in RE processes.

ERO Enterprise enforcement activities in 2016 focused on addressing serious risk issues through enforcement actions and analysis of serious risk noncompliance to identify emerging trends, patterns, and areas of focus.

Oversight Activities

NERC's CMEP oversight in 2016 focused on completion and content review of risk-based CMEP activities. In addition to tracking completion of risk-based CMEP activities, NERC's compliance monitoring oversight included review of select IRAs to determine how REs assessed risk for registered entities. Oversight of enforcement activities included process reviews for the Find, Fix, Track, and Report (FFTs), Compliance Exception (CE), and the Self-logging Programs. NERC also continued its oversight of REs' adherence to the NERC Rules of Procedure (ROP).

Other Key Activities

With the Critical Infrastructure Protection (CIP) Version 5 Reliability Standards becoming enforceable on July 1, 2016, the ERO Enterprise began to perform compliance monitoring and enforcement activities related to these Reliability Standards, in addition to continuing transition outreach to industry. The ERO Enterprise also reviewed industry's implementation of the Physical Security Reliability Standard CIP-014-2.

[1] The "ERO Enterprise" refers to the affiliation between NERC and the eight REs for the purpose of coordinating goals, objectives, metrics, methods, and practices across statutory activities. The operation of the ERO Enterprise does not conflict with obligations of each organization through statutes, regulations, and delegation agreements. The activities discussed in this report relate to compliance monitoring and enforcement performed in connection with United States registered entities. ERO Enterprise activities outside of the United States are not specifically addressed.

Chapter 1: 2016 Accomplishments

In 2016, the ERO Enterprise focused on the use and refinement of risk-based CMEP processes. The ERO Enterprise continues to enhance its understanding of risks to the BPS, through activities such as conducting IRAs, reviewing IRA results, and analyzing dispositions of noncompliance. This chapter highlights significant CMEP activities in 2016 that demonstrate the ERO Enterprise's continued focus on risk to the BPS.

Compliance Monitoring Highlights

NERC and the REs engaged in significant collaboration to refine the IRA process and clarify the use of internal controls in CMEP activities, as well as develop the 2016 ERO Enterprise CMEP Implementation Plan. Through this collaboration, NERC and the REs assessed risk on an entity level as well as across the ERO Enterprise. These activities allowed the ERO Enterprise to develop a deeper and more documented understanding of the BPS and registered entities.

Refined Risk-based Compliance Monitoring Processes

In 2015, the ERO Enterprise identified a need for a mechanism to incorporate lessons learned to enhance risk-based compliance monitoring processes. With this objective in mind, the ERO Enterprise initiated a project to review the IRA and Internal Control Evaluation (ICE) processes for opportunities for refinement. The project team focused on finding key areas for the REs to align their processes. The REs refined their regional processes in Q4 2016 and will begin using them in 2017. NERC also performed oversight visits to each RE to assess the progress of implementation of the refined processes.

IRA Process Refinement

REs perform an IRA to identify areas of focus to monitor compliance with NERC Reliability Standards for a particular registered entity. An IRA considers factors such as assets, systems, geography, interconnectivity, and functions performed. The frequency of updating an IRA may vary based on occurrence of significant changes to reliability risks or emergence of new reliability risks.

The result of the IRA process refinement effort is a common set of 18 risk factors and associated Reliability Standards that create a quantitative starting point for every registered entity across the ERO Enterprise. From there, REs may modify risk determinations based on other entity-specific considerations with a technical justification. These common risk factors help to ensure that REs assess and document risks for every registered entity.

A key deliverable of the project to assess risk-based CMEP refinement opportunities was the ERO Enterprise Guide for Compliance Monitoring.[2] The ERO Enterprise Guide for Compliance Monitoring details the process for IRA and COP development. A component of the IRA process is the risk factor review and assessment criteria used for determinations of high, medium, or low risks. The criteria provided for each risk factor serves as guidelines and help promote a repeatable process for assessing quantitative areas of risk. Additionally, the ERO Enterprise Guide for Compliance Monitoring identifies minimum COP outputs, which include the NERC Reliability Standards for monitoring, the interval of monitoring activities, and the type of CMEP tool used for monitoring. Other considerations that inform COP development include risk elements, entity performance, internal controls, and mitigating activities.

[2] Formerly known as the ERO Enterprise IRA Guide, the ERO Enterprise Guide for Compliance Monitoring incorporated language on COPs and risk elements, in addition to overall enhancements to the IRA process. The ERO Enterprise Guide for Compliance Monitoring is available at http://www.nerc.com/pa/comp/Reliability%20Assurance%20Initiative/ERO%20Enterprise%20Guide%20for%20Compliance%20Monitoring.pdf.

Internal Controls Refinement

During 2016, NERC and the REs reviewed lessons learned from ICE implementation and identified enhancements to the existing ICE process and use of internal controls. The ERO Enterprise clarified how it considers internal controls during ICE and compliance monitoring activities, such as Compliance Audits. The ERO Enterprise also streamlined its testing approach to focus on internal controls design and implementation effectiveness. The ERO Enterprise detailed these enhancements in the ERO Enterprise Guide for Internal Controls.[3] These refinements help the ERO Enterprise and industry to consider internal controls effectively in risk-based compliance monitoring.

2016 ERO Enterprise CMEP Implementation Plan[4]

Part of the risk-based framework is prioritization of continent-wide risks, which results in an annual compilation of risk elements applicable across the ERO Enterprise. Through the identification of risk elements and with input from the REs, NERC associates a preliminary list of applicable NERC Reliability Standards and responsible registration functional categories to the risk elements. REs further consider local risks when developing region-specific risk elements.[5] REs consider the Compliance and Certification Committee (CCC)[6] Criteria on risk elements, which are part of the RE evaluation criteria.[7] This initial association of Reliability Standards to risks provides one input into compliance monitoring determinations. The ERO Enterprise may, however, further refine monitoring determinations based on specific facts and circumstances about the registered entity.

As demonstrated in Table 1.1 below, the 2016 ERO Enterprise risk elements did not change significantly from the 2015 risk elements. Although the ERO Enterprise recognizes that overall risks to the BPS may remain constant from year-to-year, it continues to assess whether new risks arise or areas of focus need to change throughout the year. For instance, in June 2016, NERC added vegetation management as an area of focus under the ERO Enterprise risk element Maintenance and Management of BPS Assets. NERC noted that transmission outages related to inconsistent vegetation management pose an ongoing reliability risk to the BPS. NERC based its assessment on the 2015 Vegetation Report that shows a slight increase in grow-in vegetation-related outages.[8] NERC included FAC-003-3 as an associated Reliability Standard to the vegetation management area of focus to address the risk posed by vegetation growth.

Table 1.1: Comparison of 2015 and 2016 Risk Elements

2015 Risk Elements	2016 Risk Elements
Cyber Security	Critical Infrastructure Protection
Extreme Physical Events	Extreme Physical Events
Infrastructure Maintenance	Maintenance and Management of BPS Assets

[3] Formerly known as the ERO Enterprise ICE Guide, the ERO Enterprise Guide for Internal Controls is available at http://www.nerc.com/pa/comp/Reliability%20Assurance%20Initiative/Guide_for_Internal_Controls_Final12212016.pdf.
[4] 2016 ERO Enterprise CMEP Implementation Plan, available at http://www.nerc.com/pa/comp/Resources/ResourcesDL/2016%20CMEP%20IP_v_2%205_071116_POSTED.pdf.
[5] The 2016 ERO Enterprise Implementation Plan includes further detail on the REs' risk element development process in the RE appendices.
[6] The CCC is a NERC Board-appointed stakeholder committee serving and reporting directly to the NERC Board of Trustees. In accordance with Section 402.1.2 of the NERC ROP, the CCC is responsible for establishing criteria for NERC to use to evaluate annually the goals, tools, and procedures of each RE CMEP to determine the effectiveness of each such program.
[7] Criteria for Annual RE Program Evaluation, CCC Monitoring Program – CCCPP-010-4, October 2016, http://www.nerc.com/comm/CCC/Related%20Files%202013/CCCPP-010-4%20Criteria%20for%20Annual%20Regional%20Entity%20Program%20Evaluation.pdf.
[8] Vegetation-Related Transmission Outages – Annual Report 2015

<table>
<tr><th colspan="2">Table 1.1: Comparison of 2015 and 2016 Risk Elements</th></tr>
<tr><td>Monitoring and Situational Awareness</td><td>Monitoring and Situational Awareness</td></tr>
<tr><td>Protection System Misoperations</td><td rowspan="2">Protection System Failures</td></tr>
<tr><td>Uncoordinated Protection Systems</td></tr>
<tr><td rowspan="2">Long-Term Planning and System Analysis</td><td>Event Response and Recovery</td></tr>
<tr><td>Planning and System Analysis</td></tr>
<tr><td>Human Error</td><td>Human Performance</td></tr>
<tr><td>Workforce Capability</td><td>Not Applicable for 2016</td></tr>
</table>

Enforcement Highlights

In 2016, higher-risk cases continued to be a small percentage of the overall caseload. Generally, the noncompliance posing the greatest level of risk to reliability involved CIP Reliability Standards, vegetation contacts, repeat conduct, and entities undergoing corporate changes. The NERC Board of Trustees Compliance Committee (BOTCC) approved 18 Full Notices of Penalty (Full NOPs) resolving CIP and non-CIP violations throughout 2016. The penalties for these NOPs totaled $4,208,000.

There was no substantive change to the ERO Enterprise's penalty approach in 2016. The ERO Enterprise continued to focus on higher-risk areas by using all existing tools, including appropriate penalties, to encourage desired behavior.

NERC staff also regularly analyzes minimal risk noncompliance that is resolved as CEs (under the Self-Logging Program and otherwise) and FFTs to look for trends and emerging risks and continued to do so in 2016.

Included in Appendix A are enforcement processing goals and metrics and other relevant trends. These metrics indicate that the streamlined CE and FFT disposition methods have allowed the ERO Enterprise to resolve more efficiently minimal or moderate risk noncompliance.

2016 Disposition of Noncompliance

Below are summaries and statistics regarding the four disposition methods used to resolve noncompliance in 2016.

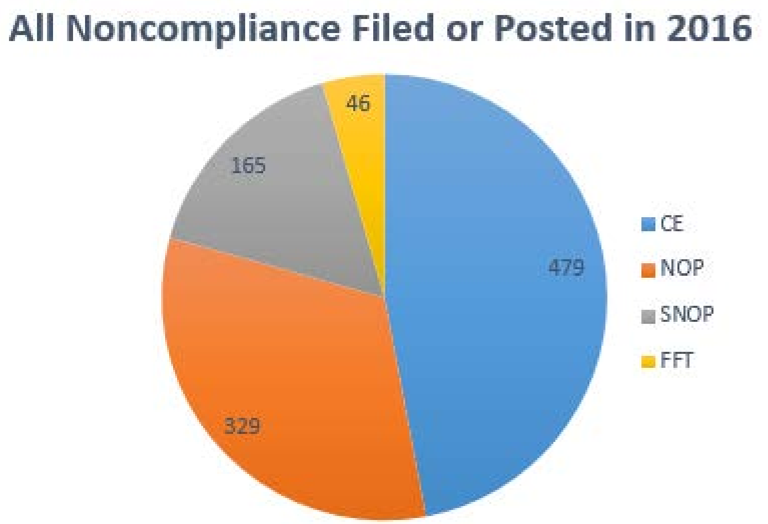


Figure 1.1: All Noncompliance Filed or Posted in 2016

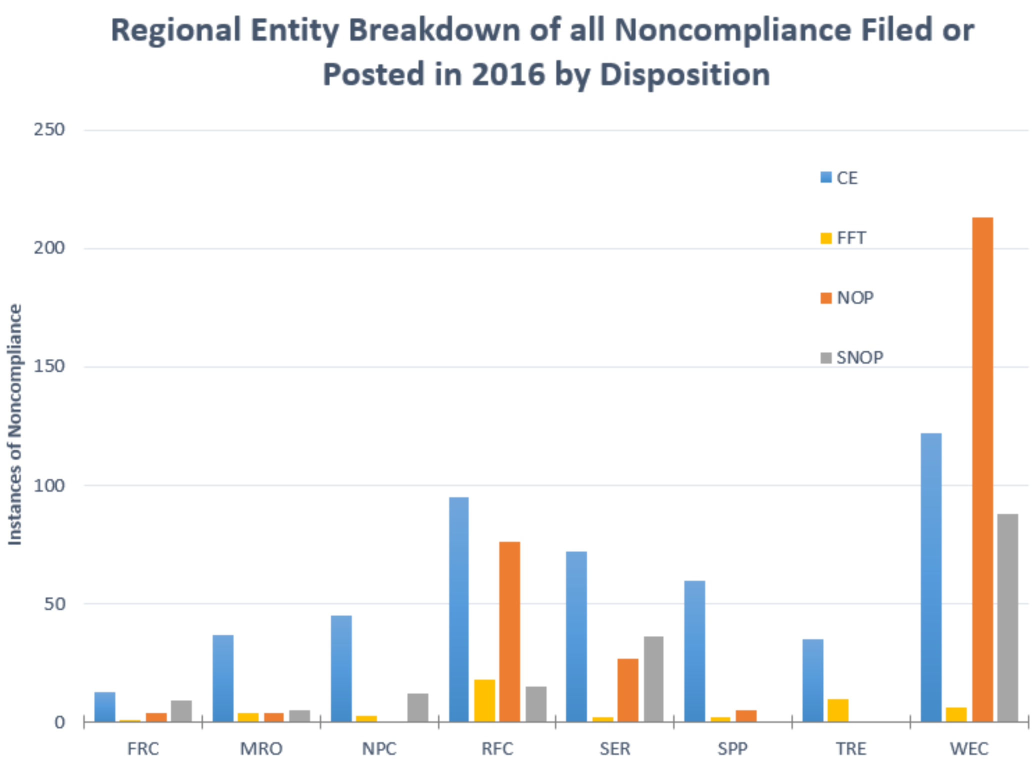


Figure 1.2: RE Breakdown of all Noncompliance Filed or Posted in 2016 by Disposition[9]

Full NOPs

Full NOPs generally include noncompliance that poses a serious or substantial risk to the reliability of the BPS, including those involving extended outages, uncontrolled loss of load, cascading blackouts, vegetation contacts, systemic or significant performance failures, intentional or willful acts or omissions, and gross negligence. Full NOPs may also be appropriate for a registered entity that has a large number of minimal or moderate risk violations that could be indicative of a systemic issue, dispositions involving higher than typical penalty amounts,

[9] In 2016, WECC processed a large number of older cases that were filed as Full NOPs.

or those with extensive mitigation or "above and beyond" actions taken by the registered entity. Full NOPs are approved by NERC and filed with FERC for review and approval. In 2016, out of 1019 instances of noncompliance posing various levels of risk, the ERO Enterprise processed 329 (32.3 percent) of those as Full NOPs.

Focus on Serious Risk Issues

The serious risk issues addressed in Full NOPs in 2016 included the following:

- A lack of commitment to NERC compliance regarding CIP Reliability Standards,
- Vegetation contacts,
- Repeat conduct,
- Ineffective change management, including employee turnover,
- Lack of preparedness for the interconnection of new facilities and the enforceability of new requirements, and
- Inadequate training of personnel on tools and processes.

NERC and RE representatives also analyzed serious risk violations from 2012 through the end of 2015. This analysis noted frequently observed issues from serious risk noncompliance and included associated recommendations that may benefit industry when evaluating risks and assessing their internal controls.

The analysis identified the following common issues involved in serious risk noncompliance that had an observable impact[10] on the reliability of the BPS:

- Less than adequate situational awareness,
- Less than adequate real-time tools or lack of real-time visibility,
- Failure to validate accuracy of BPS operating limits, such as Interconnection Reliability Operating Limits (IROL) and System Operating Limits (SOL),
- Lack of awareness regarding dependencies between redundant systems or between primary and backup systems, as well as an inability to exercise backup systems,
- Failure to disseminate information to applicable entities,
- Failure to issue clear, concise, and definitive Reliability Directives to maintain reliability, and
- Change management practices lacking risk and impact analysis.

Some of the common issues observed in the analysis were also identified as 2016 ERO Enterprise risk elements. To address these common issues, NERC and RE representatives recommended the enhancement of risk management, programs, and practices through conducting the following, among other activities:

- Risk and impact evaluations as part of change management;
- Validation of BPS limits (IROL and SOL) and ensuring the accuracy of other critical data;
- Periodic reviews to assess the sufficiency of existing processes, systems, training, and practices to identify issues early;
- Creating robust processes, tools, training, and programs to maintain system reliability; and
- Reviewing and testing the sufficiency of contingency and recovery plans.

[10] Figure A.14: Noncompliance Posing an Impact to the BES by Quarter, included in Appendix A, provides additional information regarding observable impact.

The ERO Enterprise will continue to monitor areas posing the greatest level of risk to reliability and enforce any noncompliance appropriately.

Spreadsheet Notices of Penalty

Spreadsheet Notices of Penalty (SNOPs) include noncompliance posing a minimal or moderate risk to the reliability of the BPS. Once REs have entered into Settlement Agreements with, or have issued Notices of Confirmed Violations (NOCVs) to, the registered entities, that information is reported to NERC for oversight review and approval. NERC then files that information with FERC in a spreadsheet format for review and approval. The SNOP identifies the following: the RE, the registered entity, disposition as a NOCV or Settlement Agreement, a description of the violation, the appropriate Reliability Standard, Violation Risk Factor and Severity Level, the assessed risk of the violation, total penalty or non-monetary sanction, method of discovery, mitigation activities, mitigation completion date, date RE verified mitigation completion, an admission or no contest to the violation, and other factors affecting the penalty determination, such as compliance history, internal compliance program, and compliance culture. In 2016, out of 946 minimal or moderate risk noncompliance, the ERO Enterprise resolved 164 (17.4 percent) as SNOPs.

Continued Success of the CE Program

As shown in Figure 1.1 above, CEs continue to be the dominant disposition method for noncompliance posing a minimal risk to the reliability of the BPS that does not warrant a penalty. Under this program, the noncompliance is recorded and must be mitigated within 12 months of the time of NERC's public posting of CEs.[11] Because noncompliance with any of the Reliability Standards may be treated as Compliance Exceptions, the exercise of appropriate judgment to process noncompliance as such is informed by the facts and circumstances of the noncompliance, the risk posed by the noncompliance to BPS reliability, and the potential deterrent effect of a penalty, among other things. In 2016, out of 1019 instances of noncompliance posing various levels of risk, the ERO Enterprise processed 479 (47 percent) of those as Compliance Exceptions.

To assess trends and emerging risks, NERC staff reviewed 630 CEs that were processed in 2014 and 2015. Even though these CEs involved a diverse array of underlying conduct, facts, and circumstances, the analysis identified the following primary themes and conclusions:

- Noncompliance consisted of minor mistakes when implementing programs, such as conflicting program requirements or inadequate communication between departments, as opposed to a more widespread failure or lack of mature programs. In other words, the instances of noncompliance were not due to major organizational or programmatic deficiencies.
- Many of the registered entities discovered the noncompliance through strong internal review processes, internal audits, and other detective controls. These instances of noncompliance were not due to fundamental failures in internal controls.
- Noncompliance related to previous noncompliance was not due to a failure in previously implemented mitigation.
- While many of the reviewed CEs included updates to the internal processes combined with internal training in the mitigating activities, the majority of these CEs did not have deficient past training or lack of

[11] On January 13, 2017, FERC issued an Order on NERC's annual report on the FFT and CE Programs filed November 14, 2016. FERC's Order accepted the filing and NERC's request for approval of the adjustment of time for completing mitigation activities for CEs to 12 months from the date of posting of the CE to align the completion activity timeframes with FFTs. The effective date for the new timeframe is January 13, 2017. *North American Electric Reliability Corporation,* Letter Order, Docket No. RC11-6-005 (FERC Jan. 13, 2017). Previously, the accepted timeframe for completing mitigating activities for CEs was 12 months from the time of the notification to the registered entity of CE treatment.

internal processes or procedures. Instead, the nature of the procedural changes and training was aimed at providing clarity and raising overall awareness within relevant departments at the registered entity.

FFT Program

The ERO Enterprise uses the FFT program primarily to resolve moderate risk noncompliance that does not warrant a penalty. Similar to CEs, FFTs mirror the same process of identifying, assessing, and correcting minimal or moderate risk noncompliance. Nonetheless, the ERO Enterprise uses FFTs primarily to resolve moderate risk issues that are suitable for streamlined treatment (as opposed to through a NOP). FFTs also may be used to process minimal risk noncompliance that is related to a moderate risk issue being resolved as an FFT. In addition, as with CEs, FFTs are not subject to penalties. Currently, the only major difference between CEs and FFTs is that, unlike CEs, FFTs become part of a registered entity's compliance history.[12] In 2016, out of 946 instances of minimal or moderate risk noncompliance, the ERO Enterprise processed 46 (5.1 percent) as FFTs.

Self-Logging Use

In 2016, the ERO Enterprise continued to allow eligible registered entities to participate in the Self-Logging Program. After a formal review of internal controls, a registered entity may be approved for the program and may log noncompliance for subsequent review in lieu of submitting a Self-Report. The log is limited to noncompliance posing a minimal risk to the reliability of the BPS. Approved registered entities maintain a log with a detailed description of the noncompliance, the risk determination, and the mitigating activities completed or to be completed. There is a rebuttable presumption that minimal risk noncompliance logged in this manner will be resolved as a CE. The RE reviews the logs and makes the logged noncompliance available for review by NERC and Applicable Governmental Authorities.

There are currently 59 registered entities approved by the REs to self-log as of December 31, 2016.[13]

[12] CEs are not considered part of a registered entity's compliance history except in limited circumstances. North American Electric Reliability Corporation, 150 FERC ¶ 61,108 at P 44 (2015).

[13] The number of registered entities approved by the REs to self-log decreased in Q4 due to three entities that joined a Joint Registration Organization with another entity.

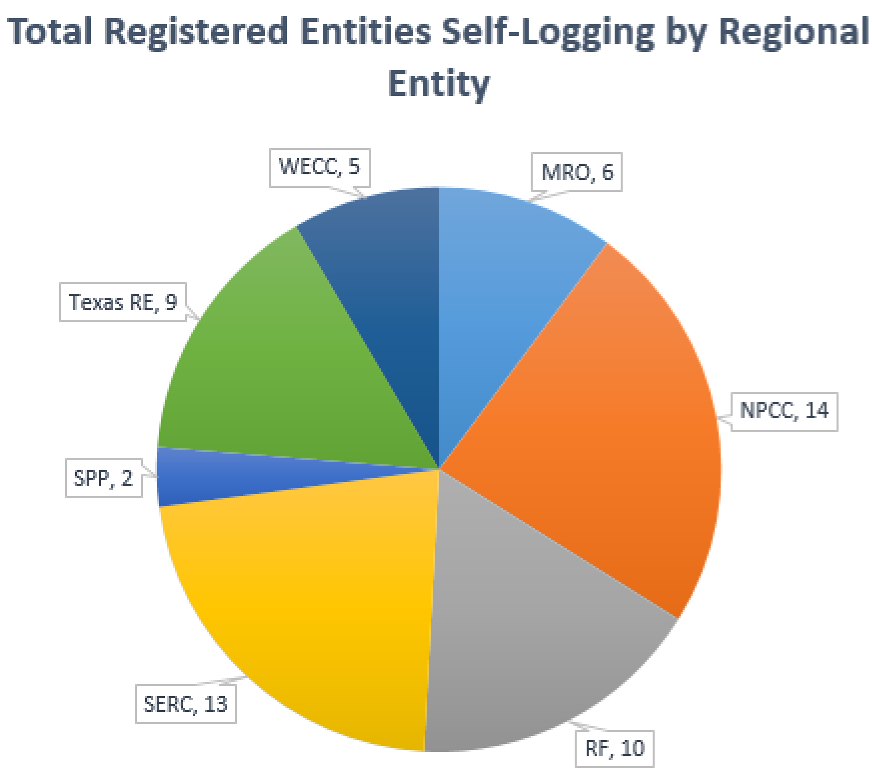


Figure 1.3: Total Registered Entities Self-Logging by RE

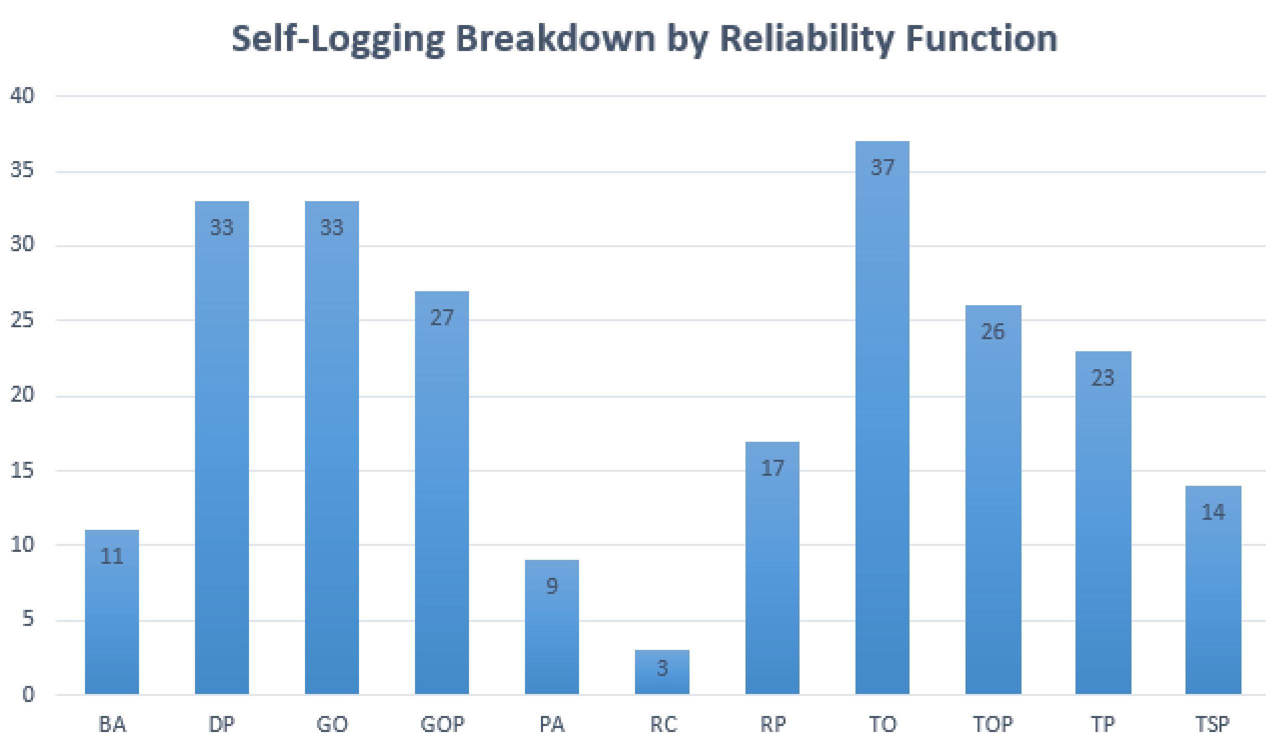


Figure 1.4: Self-Logging Breakdown by Reliability Function

Chapter 2: NERC Oversight of the Regional Entities

NERC performs oversight of REs to ensure that each RE carries out its CMEP in accordance with the NERC ROP and the terms of the delegation agreement. This chapter highlights NERC's 2016 oversight activities.

Compliance Monitoring Oversight

In 2016, NERC focused on reviewing the content of select completed IRAs; enhancing procedures for the Coordinated Oversight of Multi-Region Registered Entities (MRREs); reviewing performance of compliance monitoring activities, including audits; and verifying RE adherence to select ROP provisions. Each of these activities helps to ensure that the ERO Enterprise continuously improves its processes and meets specified criteria, such as ROP requirements or procedures of the Coordinated Oversight Program for MRREs.

Risk-based Compliance Monitoring Activities

In 2015, the ERO Enterprise developed processes to execute risk-based compliance monitoring activities and implemented the processes in 2015 and 2016. Throughout 2016, NERC's oversight focused on reviewing content of select IRAs and tracking completion of IRA and ICE activities.

IRAs

Content Review

NERC continued to review completed IRAs as part of its oversight activities concurrently with the IRA refinement project. NERC selected an IRA sample[14] to review supporting documentation to ensure REs followed ERO Enterprise guidance on justifying and documenting risk determinations. NERC used the CCC Criteria on IRAs to inform its review. In addition, NERC looked for consistent outcomes for similarly situated registered entities and technical justifications for deviations from the risk factor criteria.

Based on its review of supporting documentation, NERC found REs adequately demonstrated risk determination in accordance with the IRA guidance in effect during 2016. Nevertheless, NERC noted documentation enhancement opportunities and recommended improvements to ensure sufficient documentation exists for professional judgment and conclusions reached during IRA and COP development. For example, over-reliance on automation and regional tools may affect the quality of evidence showing RE technical justifications around entity-specific risk areas. REs should ensure tools allow for adjustments and clear methods for IRA risk determinations. Additionally, NERC noted a lack in the quantity of evidence readily available to demonstrate conclusions around IRA results and compliance monitoring decisions. For example, NERC identified a direct link between IRA results and sampled audit scopes; nevertheless, documentation around the basis for CMEP tool selections and final scope of monitoring decisions needs to be refined.

NERC selected a sample of IRAs received from REs and reviewed the registered entity's corresponding audit report or notification letter. NERC reviewed the audit scope to determine whether it covered some of the highest risks identified in the IRA for that registered entity. Of the audit scopes reviewed, NERC found that the majority of Reliability Standards in scope corresponded to a high or medium risk identified in the IRA for that registered entity. Other Reliability Standards were included in scope based on some other entity-specific facts and circumstances, such as the addition of a new registered function. Therefore, NERC observed that REs monitored some of the highest risks for that particular registered entity. In 2017, NERC will continue to review IRAs and compliance monitoring activities to understand how REs address risk, as Compliance Audits are only one method. Nonetheless, the ERO Enterprise took a significant step toward risk-based compliance monitoring by using individual entity IRAs to inform its audit activities.

[14] NERC, in coordination with FERC, sampled IRAs for 2016 non-CIP audits across all eight REs. The sample focused on non-CIP audits due to the transition to CIP Version 5 and the mid-year effective date for CIP Version 5 Reliability Standards.

Completion

In 2016, the ERO Enterprise set a goal of completing IRAs for all Reliability Coordinators (RCs), Balancing Authorities (BAs), and Transmission Operators (TOPs), as well as completing an IRA for every registered entity audited in 2016. As noted above, the completion of IRAs is necessary to help ensure compliance monitoring activities focus on high-risk areas and entity-specific risks. REs developed plans and a schedule for the completion of IRAs for all registered entities within their footprint. Included in Appendix A are further details on each RE's plan.

REs performed IRAs on 97 percent of registered entities on the 2016 audit schedule before the start of each registered entity's audit. For the remaining three percent, WECC scheduled and conducted two Compliance Audits and four Spot Checks scoped using the WECC legacy process of entity risk assessment and Regional Risk Assessment in the 2016 CMEP Regional Implementation Plan.

By the end of 2016, the ERO Enterprise completed IRAs for 62 percent of registered entities.[15] Table 2.1 shows the number of completed IRAs per RE, including IRAs for RCs, BAs, and TOPs. REs have completed IRAs for all entities registered as RCs. There are eight remaining IRAs to be completed for entities registered as BAs and TOPs, including one IRA for an entity in the Coordinated Oversight Program for MRREs.

Table 2.1: ERO Enterprise IRA Completion for Registered Entities

	FRCC	MRO	NPCC	RF	SERC	SPP RE	Texas RE	WECC	Total
IRAs for RCs, BAs, and TOPs	15	28	19	18	31	19	19	51	200
Other IRAs	26	58	182	65	99	77	141	39	687
Total	**41**	**86**	**201**	**83**	**130**	**96**	**160**	**90**	**887**

ICE Completion

In 2016, REs completed an ICE for 22 registered entities. Since initial implementation of risk-based compliance monitoring beginning in 2014, REs conducted ICEs for 61 registered entities.[16] Table 2.2 provides the total number of ICE activities completed by each RE during 2016 and in total since program implementation.

Table 2.2: ERO Enterprise ICE Completion

	FRCC	MRO	NPCC	RF	SERC	SPP RE	Texas RE	WECC	Total
ICEs Completed in 2016	1	2	11	0	0	5	1	2	22

Registered Entity Compliance Audits and Spot Checks

In 2016, REs conducted Compliance Audits and Spot Checks for 201 registered entities. REs performed Compliance Audits for 179 registered entities, Spot Checks for 19 registered entities, and combined Compliance Audits and

[15] This percentage is based on 1,436 registered entities as of June 1, 2016.

[16] Total number of ICEs conducted to date includes ICEs initiated in 2015 and excludes prior ICE-related activities that followed legacy regional processes during 2014 and 2015.

Spot Checks for three registered entities. NERC conducted oversight activities for Compliance Audits and Spot Checks, including observations of select registered entity audits. The following subsections provide highlights of NERC's oversight activities related to registered entity Compliance Audits and Spot Checks.

Compliance Audit Observations

NERC sampled a selection of RE audits of registered entities to observe and review. Through audit observations, NERC both monitors the audit process, including audit-scoping determinations, and assesses the REs' evaluations of registered entity compliance with NERC Reliability Standards. Further, audit observations help NERC to assess the overall implementation of ERO Enterprise activities, such as risk-based compliance monitoring, CIP Version 5 transition, Physical Security Reliability Standard implementation, and the Coordinated Oversight Program, and to identify program development needs, training, and outreach. In 2016, NERC observed a total of 19 audits with audit scopes including both CIP and non-CIP Reliability Standards and with registered entities within the Coordinated Oversight Program. NERC identified positive observations and opportunities for improvements to compliance monitoring as follows:

- REs followed the processes within the CMEP, ROP Appendix 4C for Compliance Audits, and the processes and procedures within the ERO Enterprise Auditor Handbook and Checklist.
- Audit teams provided transparency and discussion opportunities with the registered entities in instances of possible findings of noncompliance.
- Audit teams made effective use of off-site pre-audit reviews by collecting and testing evidence before any on-site activities.

NERC also observed REs taking a risk-informed approach to sample and visit substations in an effort to focus resources to test compliance within high-risk areas. For example, to test facility ratings, audit teams toured substations to determine that all visible and applicable components (such as transformers and jumpers) were correctly accounted for in the facility ratings documentation. To test completion of relay populations, audit team members also confirmed that relay panels are accounted for, and they inspected a sample of panels to ensure that all relays on them are accounted for in the relay population. NERC considers this testing approach an ERO Enterprise best practice when warranted by risk. This approach provides additional assurance of the accuracy of provided populations for certain higher risk areas and helps ensure the overall reliability of the BPS.

NERC observed improvement opportunities for audit teams to understand better the registered entity's existing internal controls that support compliance with the Reliability Standards and an opportunity for improvement in overall documentation of professional judgment and analysis to determine compliance. ERO Enterprise staff training in 2017 will focuse on understanding a registered entity's internal controls related to Reliability Standards and documenting decisions around compliance and internal controls during compliance monitoring activities.

Areas of Concern and Recommendations Review

NERC receives registered entity Compliance Audit and Spot Check reports from REs. While NERC publicly posts audit reports, the RE redacts non-public information, including areas of concern, and NERC does not post the reports until disposition of open enforcement actions. NERC reviewed a sample of audit reports it received in 2016 to identify themes noted in areas of concern and recommendations. An area of concern relates to a situation or area that is not a violation of a Reliability Standard or requirement but could become a violation based on the observed circumstances. Recommendations consist of areas or situations in which an opportunity may exist for improving compliance-related processes, procedures, or tools. Included in Appendix A are summaries of some of the areas of concern and recommendations from non-CIP and CIP audit reports reviewed by NERC in 2016.

Review of Registered Entity Post-audit Feedback Surveys

Following every Compliance Audit, registered entities have an opportunity to complete post-audit feedback surveys. Both NERC and the REs review registered entity feedback to help enhance risk-based compliance monitoring activities. Post-audit feedback surveys aim to provide a feedback loop to NERC and the REs by identifying successes and opportunities for program development, as well as possible education and training opportunities for ERO Enterprise staff.

In 2016, NERC and the REs collected 66 post-audit feedback surveys, which is a response rate of about 33 percent of the total number of entities that had Compliance Audits in 2016. Overall, survey responses indicated continued support by registered entities of the risk-based compliance monitoring approach, noting that most Compliance Audits had a clear focus of monitoring efforts on reliability risk. Further, registered entities noted their appreciation for the audit team's flexibility in audit scheduling, clear and transparent communication during the audit, and the professional demeanor of the audit team. Registered entities also commended the audit teams' review of large volumes of work during the off-site pre-audit portion that resulted in over 77 percent of responses saying compliance monitoring activities caused little to moderate disruption of operations. Additionally, feedback surveys indicated an opportunity for the ERO Enterprise to improve communication regarding the audit notification package, IRA and ICE results, and the impact of those results on determining monitoring scope and method.

Coordinated Oversight of MRREs

The ERO Enterprise continues to collaborate toward effective, consistent, and efficient implementation of coordinated oversight for MRREs in the Coordinated Oversight Program. To that end, in 2016 the Coordinated Oversight Task Force (COTF) was formed to assist the ERO Enterprise with, among other things, developing common procedures, identifying process improvement needs, and obtaining input from MRREs participating in coordinated oversight.

The COTF surveyed current MRRE groups participating in the Coordinated Oversight Program and found that 97 percent of the MRREs support continued participation in the program, while 89 percent contend that the program fulfills its objectives. From the survey results, the COTF identified enhancement opportunities, particularly in the areas of IRAs, Technical Feasibility Exceptions (TFEs), and data submittals. The ERO Enterprise will address lessons learned through oversight and training.

During 2016, 35 additional registered entities opted in to the Coordinated Oversight Program, taking the total count of registered entity participation to 213.[17] The ERO Enterprise continued to consider opportunities to refine the Coordinated Oversight Program and to improve associated efficiency and consistency while also fulfilling obligations for implementation of the CMEP. Included in Appendix A are additional supporting details on the Coordinated Oversight Program.[18]

ROP Adherence Verification

Each year, NERC focuses its oversight on certain provisions of the ROP. In 2016, NERC conducted a review of training completed by CMEP staff that participate in audits; verified that REs conduct an on-site audit every three years for RCs, BAs, and TOPs; and confirmed that REs completed monitoring activities in the 2016 ERO Enterprise CMEP Implementation Plan.

Other Oversight Activities

NERC continuously reviews RE activities for opportunities for consistency. NERC and the REs noted an opportunity for alignment in updating templates used by the REs. For instance, NERC and the REs revised the audit report template, and they will use the updated report for 2017 Compliance Audits. In addition, NERC and the REs will

[17] This report reflects the total number of registered entities participating in the program regardless of whether the NERC Compliance Registry number is unique or identical across the REs.

[18] Information on the Coordinated Oversight of MRREs Program is available at: http://www.nerc.com/pa/comp/Reliability%20Assurance%20Initiative/MRRE%20FAQ%20with%20Notice%201-12-15.pdf.

review the 90-day notification letters for Compliance Audits to develop a common template. Throughout revision of the templates, the ERO Enterprise employed the CCC Criteria to manage scope and content of the review.

Enforcement Oversight

NERC's enforcement oversight in 2016 focused on the following key areas: process reviews, risk determinations, and settlements and penalty determinations.

Process Reviews

As part of its oversight role, NERC staff routinely evaluates each RE's enforcement program, as well as samples of specific cases.

CE and FFT Programs Review Results

In 2016, NERC staff, along with FERC staff, completed an annual process review of the CE and FFT programs. This combined review evaluated RE implementation of the CE and FFT programs to ensure alignment with applicable ERO Enterprise program documents and guidance.

The review[19] found that the REs appropriately included the sampled noncompliance in the FFT and CE programs and that the registered entities adequately mitigated all 132 instances of noncompliance, including 11 self-logged CEs (approximately 10ten percent of the CEs reviewed).

NERC staff also agreed with the final risk determinations for all CEs and FFTs sampled, and noted with the REs significant improvement in the clear identification of root cause in all samples posted after the feedback calls from the previous year's survey. FERC staff also concurred with NERC that the FFT and CE programs are meeting expectations.

The results of the 2015 annual review show a consistent improvement in program implementation. They indicate, among other things, that most registered entities, in coordination with their respective RE, are able to identify, mitigate, and remediate minimal – as well as certain moderate – risk noncompliance. They also show significant alignment across the ERO Enterprise, including the understanding of risk associated with individual noncompliance.

NERC submitted an annual report on the FFT and CE Programs to FERC in November 2016.[20] NERC and FERC staff have already begun working on the 2016 annual FFT and CE program sampling for the 2017 process review.

Self-Logging Program Process Review

In 2016, NERC conducted a Self-Logging Program process review, as well as surveyed the REs to assess the overall program implementation and identify any barriers to increased levels of participation in the program, given the moderate expansion of the program since 2015.

NERC's review confirmed that the majority of REs are consistently implementing the Self-Logging Program. NERC found that self-logging noncompliance reduces processing times by two-thirds when compared with Self-Reports. Self-logged noncompliance was accurately assessed and had a low instance of dismissal. Communication between the registered entity and RE increased. In addition, the ERO Enterprise has a more thorough understanding of the risk posed by noncompliance across the BPS because of active participants in the program.

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[19] For FFTs, the program year was October 1, 2014, through September 30, 2015. For CEs, the review period was May 1, 2014, through September 30, 2015.

[20] Annual Report on the FFT and CE Programs, available at http://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/FinalFiled_2016%20Annual%20FFT%20and%20CE%20Report_11-14-16.pdf.

Many REs are conducting successful outreach to their registered entities on the benefits of self-logging. Nevertheless, NERC and the REs have observed that many registered entities are not fully aware of the benefits of the Self-Logging Program and are hesitant to seek eligibility for the program because of a perceived lack of incentives.

Based on the findings from the Self-Logging Program process review, NERC will propose to provide CEs identified through self-logging to FERC on a non-public basis. NERC determined that the non-public posting of logged CEs would encourage self-logging participation and realign the focus of the public on higher risk issues by eliminating public notice of registered entity noncompliance without any identified negative impacts to the BPS. Further, making self-logs non-public would distinguish the program from the publicly posted CEs identified through other discovery methods.

This revision to the program would reflect the original tenets of self-logging: presumption of CE treatment and self-logged items that are subject to periodic regional review and treated in a non-public manner.

Determinations of Risk Associated with Specific Noncompliance

In 2016, NERC and RE staff participated in two face-to-face risk calibration training sessions. These sessions included open discussions, as well as exercises to facilitate targeted dialogue. The exercises used case studies and fact patterns developed from actual cases.

The results of these exercises demonstrated considerable alignment across the ERO Enterprise in determining the risk associated with specific noncompliance.

Exercises like these also provide for continuous development as ERO Enterprise enforcement staff engage in shared learning and incorporate this knowledge into day-to-day activities.

Settlement and Penalty Determinations

NERC regularly oversees RE enforcement activities to evaluate the appropriateness of disposition methods, including assessment of a penalty or sanction. Similar to the risk calibration exercises, NERC found alignment of penalty determinations throughout the ERO Enterprise.

The BOTCC considers the recommendations of NERC staff regarding approval of Full NOPs and monitors the handling of noncompliance through the streamlined disposition methods of CEs, FFTs, and SNOPs.

Chapter 3: ERO Enterprise CMEP Training, Education, and Outreach

ERO Enterprise Training and Education

The ERO Enterprise recognizes that continuing training and education for its CMEP staff promotes consistency and competency in conducting CMEP activities. Therefore, the ERO Enterprise provides training and education for its staff every year that focuses on the necessary skills and knowledge relevant to perform their jobs.

NERC conducted a workshop for CMEP staff in April 2016. Approximately 114 RE staff attended the workshop in person, and approximately 40 attended remotely. The workshop theme was "cross-functional collaboration," and participants could select courses on risk and penalty determinations in enforcement actions, power system frequency, and system protection. In addition, participants attended sessions on either CIP or non-CIP topics, including some sessions involving standard drafting team members from industry.

NERC staff also provided a webinar in the summer of 2016 geared toward RE staff new to the ERO Enterprise. The webinar reviewed the basics of various enforcement disposition methods, templates, and required documents for filing to aid in consistency of processes.

In October 2016, NERC and the REs held conferences for approximately 115 ERO Enterprise staff that perform compliance monitoring activities. The purpose of these conferences was to encourage cross-regional collaboration and discussion on various activities within compliance monitoring, including topics such as updates to ERO Enterprise guidance and skills used during CMEP activities.

NERC and RE enforcement staff developed and distributed an Enforcement Capabilities and Competency Guide. This guide is designed to provide a practical, hands-on resource for NERC and RE staff in identifying the combination of skills, attributes, and behaviors that are necessary for the successful performance of various enforcement roles.

In addition to the workshop, webinar, and conferences, NERC and the REs hold two sessions a year on audit team leader skills. This course ensures that audit team leaders and certification team leaders possess the requisite skills to lead a Compliance Audit or certification team. NERC also offered a course on communication skills. Finally, NERC and the REs have access to computer-based training on a learning management system.

Industry Education and Outreach

NERC held a Standards and Compliance Workshop in July 2016 in St. Louis, Missouri. NERC and RE staff covered CMEP topics such as internal controls, updates on implementation of risk-based CMEP, and the Compliance Guidance Policy. Approximately 200 participants attended the two-day workshop.

REs provided outreach through workshops, monthly newsletters, assist visit programs, and other events with industry stakeholders. In addition, NERC coordinated with RE staff on internal controls presentations at RE workshops. A majority of outreach focused on risk-based CMEP topics, particularly IRAs, although some REs anticipate a shift in the focus of outreach after 2016. For instance, Texas RE began focusing on trends in risks identified during IRAs as part of its outreach rather than simply the fundamentals of conducting IRAs. Although general outreach will shift as more registered entities gain experience with risk-based CMEP activities, some REs, such as WECC and FRCC, noted that they incorporate outreach into each IRA development process by providing walk-throughs or conversations on IRAs with registered entities. RF also met with registered entities to discuss internal controls.

Finally, NERC and the REs provided industry education on all Reliability Standards approved by FERC in 2016. Table 3.1 lists the topics covered for 2016.

Table 3.1: Education on Newly-approved Reliability Standards

Standard	Outreach
CIP-003-6, CIP-004-6, CIP-006-6, CIP-007-6, CIP-009-6, CIP-010-2, and CIP-011-2	Technical Conference
MOD-031-2	Webinar
PRC-026-1	Webinar
FAC-003-4	NERC Standards and Compliance Workshop
IRO-018-1	Webinar
TOP-010-1	Webinar
TPL-007-1	Webinar
COM-001-3	Webinar

Coordination with CCC

NERC and the REs collaborated with the CCC throughout 2016 to promote consistency across the ERO Enterprise through revisions to the CCC Monitoring Program Procedure CCCPP-010-4: Criteria for Annual RE Program Evaluation.[21] NERC consults these criteria during its oversight activities to increase alignment, and the collaboration between the CCC and the ERO Enterprise enhances the effectiveness of the criteria. The CCC members also provided input from the first year of implementation of the risk-based CMEP. That discussion highlighted a further need to explore areas where issues of consistency could be brought to the attention of the ERO Enterprise. As a result, the CCC held a roundtable discussion focused on handling consistency issues. A small group of CCC members and NERC staff discussed how NERC could collect information on consistency, review the information, and prioritize action. The recommendations or actions resulting from this discussion will be presented to the BOTCC in February 2017.

[21] http://www.nerc.com/comm/CCC/Related%20Files%202013/CCCPP-010-4%20Criteria%20for%20Annual%20Regional%20Entity%20Program%20Evaluation.pdf.

Chapter 4: Other Significant 2016 Activities

Compliance Guidance

In November 2015, the NERC Board of Trustees approved the Compliance Guidance Policy.[22] The policy outlined two types of Compliance Guidance: Implementation Guidance and CMEP Practice Guides. Implementation Guidance is developed by industry stakeholder groups and provides examples of compliance approaches for Reliability Standards. CMEP Practice Guides provide direction to CMEP staff on approaches to execute compliance monitoring and enforcement activities. CMEP Practice Guides are developed by the ERO Enterprise and do not address activities specific to one Reliability Standard unless developed in conjunction with industry stakeholders.

One recommendation from the Compliance Guidance Policy was to develop a CMEP Practice Guide that addresses deference to Implementation Guidance. In March 2016, the ERO Enterprise developed guidance on how ERO Enterprise CMEP staff provides deference to ERO Enterprise-endorsed Implementation Guidance. Under the Compliance Guidance Policy, the CMEP Practice Guide was posted on the NERC website for transparency to industry.[23]

Industry stakeholders submitted 26 documents as proposed Implementation Guidance. The ERO Enterprise developed and implemented a process to evaluate and potentially endorse the Implementation Guidance. In addition, the ERO Enterprise developed a category for Implementation Guidance that is endorsed for Inactive Reliability Standards. The ERO Enterprise determined that industry might still benefit from guidance for past standards versions during the implementation of current versions. Included in Appendix A is a table that provides detail on the documents submitted for endorsement.

CIP Version 5 Transition and Enforceability

In 2016, the ERO Enterprise concluded transition activities and began enforcing the CIP Version 5 Reliability Standards. On January 21, 2016, FERC issued an Order on the revised CIP Reliability Standards. In its Order, FERC approved seven CIP Standards (CIP-003-6, CIP-004-6, CIP-006-6, CIP-007-6, CIP-009-6, CIP-010-2, and CIP-011-2). FERC also approved the Implementation Plan, Violation Risk Factor assignments, Violation Severity Level assignments, and the revised NERC Glossary of Terms. Based on the date of the Order, its publication in the Federal Register, and the Implementation Plan approved by FERC, the compliance date for the revised CIP Version 5 Reliability Standards became July 1, 2016. FERC also issued an Order that granted an extension for compliance with the remaining CIP Version 5 Standards until July 1, 2016.

Due to the extension of the compliance date to July 1, 2016, the ERO Enterprise continued transition outreach activities, particularly for registered entities with high and medium impact BES Cyber Systems, through Q1 and Q2 of 2016. Outreach during this period was led by RE compliance monitoring staff. Regional compliance workshops often included speakers from NERC staff. Transition outreach was also the focus of engagements with registered entities that were originally scheduled for an audit to the CIP Version 5 Reliability Standards during the period; audit staff instead provided feedback to registered entities about progress toward compliance.

In addition to RE-led outreach, NERC hosted Small Group Advisory Sessions in September that focused on registered entities with low impact BES Cyber Systems. Representatives from 20 registered entities met with staff from NERC and the REs to discuss CIP Version 5 Reliability Standards implementation. Concurrent with the Small Group Advisory Sessions, the ERO Enterprise held a workshop and webinar on low impact BES Cyber Systems.

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[22] Compliance Guidance Policy available at
http://www.nerc.com/pa/comp/Resources/ResourcesDL/Compliance_Guidance_Policy_FINAL_Board_Accepted_Nov_5_2015.pdf.

[23] CMEP Practice Guide available at
http://www.nerc.com/pa/comp/guidance/CMEPPracticeGuidesDL/CMEP_Practice_Guide_Deference_for_Implementation_Guidance.pdf

After the July 1, 2016, enforceable date, NERC and the REs monitored and enforced the CIP Version 5 Standards. The ERO Enterprise developed an initial compliance monitoring plan that focused on key aspects of the CIP Version 5 Standards. While the monitoring scope of each registered entity may be modified based on its identified risks, the ERO Enterprise established a preliminary focus on CIP-002-5.1 and related Reliability Standards in the 2016 ERO Enterprise CMEP Implementation Plan, in addition to lessons learned from transition activities. For all registered entities, the ERO Enterprise coordinated an RE-executed self-certification related to the identification of assets with high, medium, and low impact BES Cyber Systems under CIP-002-5.1. After July 1, 2016, the REs audited 72 registered entities on the CIP Standards. FERC also coordinated with NERC and the REs on FERC-led audits of select registered entities.

Based on outreach and monitoring activities in 2016, the ERO Enterprise observed initial trends in how some organizations treat security controls. The ERO Enterprise noted several instances of registered entity performance that was considered a moderate or significant risk to the BPS because of organizational alignment, such as the compliance department operating independently from operations departments, operational expertise not reflected in procedures, subject matter experts unaware of compliance procedures, or insufficient executive leadership engagement. The ERO Enterprise will consider actions in 2017 to mitigate the risk to the BPS of less than adequate security controls.

The ERO Enterprise observed a decrease in the number of TFEs filed for Version 5 versus Version 3 CIP Reliability Standards. The ERO Enterprise will review the current TFEs during 2017 to understand better the change.[24]

Throughout 2016, NERC worked with the REs to conduct a comprehensive study that identifies the strength of the CIP Version 5 remote access controls, the risks posed by remote access-related threats and vulnerabilities, and appropriate mitigating controls as directed by FERC in Order No. 822. NERC will file observations or conclusions from the study with FERC in 2017.

NERC and the REs will continue to support the transition of stakeholders to CIP Version 5, particularly for registered entities with assets containing low impact BES Cyber Systems and for requirements that become effective in 2017. The compliance monitoring processes will include a technical excellence component by increasing the emphasis on the better use of tools to assess complex networks, technical (hands-on) training for CIP auditors, and enhanced consistency with additional training on the Evidence Request Spreadsheet. The ERO Enterprise will continue to collaborate with the industry to provide feedback to Reliability Standards development activities. For example, the industry and the ERO Enterprise provided feedback to the Standards Drafting Team to help address refinements based on the Lessons Learned and FAQ documents from the transition program[25] and from implementation.

Physical Security Implementation

In 2016, the ERO Enterprise focused on assessing the implementation progress of registered entities in complying with CIP-014-2. The ERO Enterprise employed two methods for determining the status of registered entities in implementation: self-certifications and voluntary outreach through on-site visits. On March 15, 2016, the REs issued a CIP-014-2 self-certification request that focused on Requirements R1, R2, and R3. To assist industry with completing the self-certification, NERC conducted a CIP-014-2 self-certification webinar that was attended by over 200 participants.

[24] NERC provides analysis on TFEs in a report annually filed with FERC. The report covering data from July 1, 2015 through June 30, 2016 is available at http://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/TFE_Annual_Report-2016_09282016.pdf.
[25] In 2014, NERC initiated a program to help industry transition directly from the currently enforceable CIP Version 3 Standards to CIP Version 5. Additional information on the program is available at http://www.nerc.com/pa/CI/Pages/Transition-Program.aspx.

The ERO Enterprise also conducted outreach through on-site engagements with 19 registered entities in six RE footprints. These site visits have provided opportunities for meaningful dialogue regarding security measures and challenges for the implementation of CIP-014-2. A primary focus was to understand how industry stakeholders have developed security plans to mitigate risks of specific threats. These outreach visits have revealed progress in the industry's implementation of CIP-014-2. Going forward, NERC and the REs will consider data collected through other methods, including Compliance Audits and other compliance monitoring activities, to gain a greater understanding of implementation.

Consolidated Hearing Process

Throughout 2016, NERC and RE legal staff collaborated to develop a Consolidated Hearing Process that would allow REs the option to select the existing RE hearing process or allow NERC to manage the hearing process. One of the key benefits of the Consolidated Hearing Process is to increase efficiency. The NERC Board of Trustees approved revisions to the ROP in November 2016 that provide for the Consolidated Hearing Process. In December 2016, NERC filed the proposed revisions to the ROP with FERC for approval and provided notice to the Applicable Governmental Authorities.

Chapter 5: Looking Ahead to 2017

To guide compliance monitoring and enforcement activities in 2017, NERC has identified the following priorities for the ERO Enterprise:

- Develop and implement compliance oversight plans for registered entities focusing on relevant risks, including consideration of inherent risk assessments and internal control evaluations;
- Implement compliance monitoring and enforcement timely and transparently, using a consistent framework;
- Enhance and implement training for ERO Enterprise CMEP staff;
- Reduce repeat noncompliance through rigorous assessment of registered entities' plans to mitigate noncompliance;
- Evaluate the existing compliance, reporting, and analysis tracking system and other compliance tools to support risk-based activities that meet the needs of the CMEP; and
- Provide guidance and outreach to registered entities, including the review of Implementation Guidance for endorsement.

Appendix A

Appendix A includes additional details on some activities described in the 2016 CMEP Annual Report. This appendix will cover RE IRA completion, areas of concern and recommendations highlights, coordinated oversight for MRREs, compliance guidance, and enforcement metrics highlights.

Compliance Monitoring

IRA Completion

This section highlights each RE's plan for completion of initial IRAs for all registered entities.[26] Completion plans may be modified due to emerging risks, changes in resources, or other relevant considerations. The plans consider initial IRAs only and not activity regarding revised or refreshed IRAs. In addition, the ERO Enterprise expects Affected Regional Entities (AREs) to provide appropriate inputs to Lead Regional Entities (LREs) for those MRREs in the Coordinated Oversight Program to create a comprehensive IRA. Therefore, the numbers below only capture an IRA completed in the LRE, but the IRA incorporates risks from all AREs.

FRCC

FRCC completed IRAs for all entities registered as BAs and TOPs in its region. There are no RCs registered in FRCC.[27] FRCC completed initial IRAs for 41 registered entities by the end of 2016 and has six registered entities remaining.

MRO

MRO planned to complete IRAs for all registered entities within its footprint by the end of 2016. MRO has completed IRAs for entities registered as RCs, BAs, and TOPs and has only eight remaining registered entities to complete. MRO is ARE for the remaining registered entities.

NPCC

NPCC completed IRAs for 201 out of 213 registered entities within its footprint by the end of 2016. Of the remaining IRAs, NPCC is the ARE for eight of the registered entities, and three are Canadian registered entities for which IRAs are not needed.

RF

RF has completed 83 IRAs out of the 231 registered entities under its footprint. RF completed IRAs for 18 entities registered as RCs, BAs, and TOPs within its footprint by the end of 2016, with an additional four IRAs pending approval under the Coordinated Oversight Program for RCs, BAs, or TOPs. RF projects completion of initial IRAs for its remaining 148 registered entities by the end of 2019. RF will prioritize the remaining entities by those on the compliance monitoring schedule each year, then by risk associated with a particular registered entity or grouping of functions.

SERC

SERC plans to complete IRAs for all of its 196 registered entities by the end of 2017. By the end of 2016, SERC completed IRAs for 31 RCs, BAs, and TOPs registered within its footprint, as well as the IRAs for entities originally scheduled on its 2016 through 2019 compliance monitoring schedules. SERC plans to complete the remaining IRAs for registered entities by the end of 2017. SERC's plan for completion considers the review of its annual RE risk assessment, then reviewing or updating completed IRAs based on newly identified risks.

SPP RE

SPP RE completed IRAs for 96 registered entities within its footprint by the end of 2016.

[26] The registered entities considered were the 1,436 registered entities as of June 1, 2016.

[27] FRCC is the RC for registered entities within its regional footprint and does not have other entities registered for that function. FRCC is registered as an RC in SERC.

Texas RE

Texas RE plans to complete IRAs for all registered entities by the end of 2017. By the end of 2016, Texas RE completed IRAs for over 160 registered entities, including all RCs, BAs, and TOPs in its footprint. In addition to the RC, BA, and TOP registrations, Texas RE has completed initial IRAs for all Transmission Planners, the Resource Planner, and the Transmission Service Provider in its footprint. Over 70 percent of initial IRAs for Generator Owners, Generator Operators, and Distribution Providers have been completed. Over 90 percent of initial IRAs for Transmission Owners have been completed. Texas RE plans to complete IRAs for the remaining registered entities by the end of 2017. Texas RE prioritizes IRAs based on registration and its RE risk assessment. For example, during 2016, Texas RE focused IRA activities on its TOPs and higher-risk entities.

WECC

WECC plans to complete initial IRA activities for all 355 registered entities by the end of 2018. By the end of 2016, WECC completed IRAs for 90 registered entities within its footprint, including those completed in 2014 and 2015. WECC completed most of the IRAs for entities registered as RCs, BAs, and TOPs. By the end of 2016, WECC completed 51 IRAs for entities registered as RCs, BAs, and TOPs. WECC expects to complete the remaining BA and TOP IRAs by the end of Q2 2017. WECC will revise its plan to account for any new registrations that occurred after December 1, 2016.

Areas of Concern and Recommendations Highlights

This section includes highlights of areas of concern and recommendations from RE audit reports.

In the non-CIP reports NERC reviewed, REs identified the greatest number of areas of concern and recommendations regarding the PRC-005 and FAC-008-3 Reliability Standards:

- PRC-005: REs often noted a need for improved documentation and retention of test records that accurately outline the maintenance activities to be completed to help ensure registered entities do not miss maintenance or testing activities.
- PRC-005: REs noted a need for alignment of the registered entity’s documented Protection System Maintenance and Testing Program with the maintenance tables in PRC-005 to help ensure registered entities do not test outside of allowable intervals.
- PRC-005: REs recommended documentation enhancements to improve completeness and consistency, such as ensuring all business units use a standardized form to document maintenance activities and capture information in a consistent and reliable fashion. Additionally the recommendations for PRC-005 included improvements to document tracking and verification or automation of such processes for completed maintenance activities.
- FAC-008: REs observed that registered entities had errors between the equipment identified in the Facility Rating documentation and actual equipment present in the field despite having the correct overall Facility Ratings or following the Facility Ratings methods correctly. While in these instances the errors did not affect the most limiting element, had equipment been replaced that resulted in a new most limiting element, it may not have been identified. This may cause the entity to operate outside of the Facility Rating, which can result in damage to or loss of useful life for equipment.
- FAC-008: RE recommendations indicated a need for improved methodology documentation to provide additional clarity on rating practices and for registered entities to review existing Facility Rating processes to ensure the methods clearly address ownership responsibilities of assets.

CIP audits during 2016 did not have an extensive focus on the requirements from Version 3 of the CIP Reliability Standards, but instead were based on the Version 5 Standards that became effective on July 1, 2016. In the first half of the year, Compliance Audits were an opportunity to evaluate a registered entity’s preparedness for implementation of Version 5; after the July 1 enforcement date, findings from a Compliance Audit could result in possible violations.

There were many areas of concern and recommendations regarding Version 5 issues that the RE auditors cited during the year. The following are some examples:

- Documentation needs to reflect terms from the Version 5 Standards (e.g., “Critical Cyber Asset” would no longer be accurate).
- Using consistent terms: for example, timeframes can be more clearly stated as "calendar months" or "calendar days" rather than “months,” “days,” or even “annual.”
- Verify that documents reflect actual procedures, including procedures that are performed occasionally (e.g., lost keycards).
- CIP-002-5.1: The BES Cyber System Assessment process should clearly indicate that all systems and facilities critical to system restoration are included (i.e., blackstart resources, Cranking Paths and initial switching requirements, and Special Protection Systems).
- CIP-002-5.1: Electronic Access Control or Monitoring Systems devices located outside the Physical Security Perimeter need to be included as Cyber Assets in the list provided to auditors.
- CIP-004-6: If a Social Security Number check is not possible, a secondary process for verifying identity, such as comparing identification documentation, could be used.
- CIP-005-5: Firewall configuration procedures should include the periodic review of firewall rule sets that will verify that all documented reasons or justifications are accounted for, and that the justifications remain valid and current.
- CIP-005-5: Firewall rules must be specific to allow only those ports that are truly needed, with adequate descriptions available to explain the business need or justification for each rule.
- CIP-006-6: Where physical keys are used as an additional security measure, consider a restricted key system to limit and control the number of keys held by individuals.
- CIP-007-6: Mitigation plans for patches that have not yet been installed must address the specific vulnerabilities the patch is designed to address, such as modifying system settings or temporarily disabling an affected service.
- CIP-009-6: Include roles and responsibilities in the Master Recovery plan or Operational Level Agreements or both.

Coordinated Oversight Program for MRREs

Table A.1 below provides the number of registered entities in the Coordinated Oversight Program for MRREs per RE.

Table A.1: Registered Entities in Coordinated Oversight Program

Lead Regional Entity	Number of Registered Entities in Coordinated Oversight Program
MRO	25
NPCC	2
RF	70

Table A.1: Registered Entities in Coordinated Oversight Program	
SERC	25
SPP RE	22
Texas RE	57
WECC	12
Total	**213**

Figure A.1 below provides the percentage of the 213 registered entities in the Coordinated Oversight Program for which each RE is the LRE.

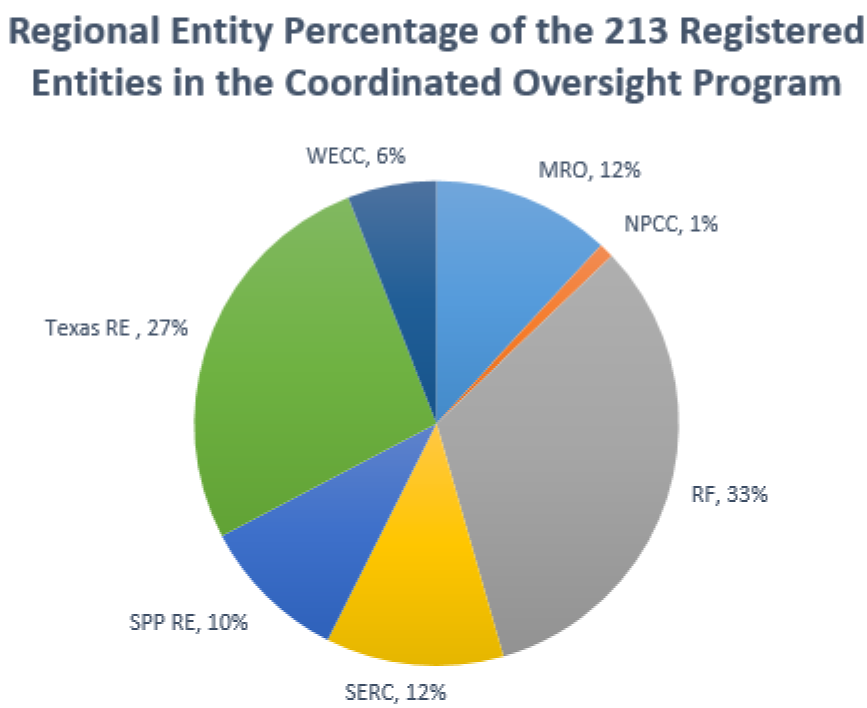


Figure A.1: RE Percentage of the 213 Registered Entities in the Coordinated Oversight Program

Compliance Guidance

Table A.2 provides a list of the documents submitted for ERO Enterprise endorsement as Implementation Guidance.

Table A.2: Implementation Guidance Submittals		
Document Title	**Submitter**	**Status**
CIP-002-5.1: Bulk Electric System (BES) Cyber Assets Lesson Learned	Compliance Guidance Policy Team	Endorsed

Table A.2: Implementation Guidance Submittals		
CIP-002-5.1: Generation Segmentation Lesson Learned	Compliance Guidance Policy Team	Endorsed
CIP-002-5.1: Far-end Relay Lesson Learned	Compliance Guidance Policy Team	Endorsed
CIP Version 5 Frequently Asked Questions	Compliance Guidance Policy Team	Endorsed
CIP-002-5.1: Communications and Networking Cyber Assets	Compliance Guidance Policy Team	Endorsed
External Routable Connectivity Lesson Learned	Compliance Guidance Policy Team	Endorsed
CIP-002-5.1: Generation Interconnection Lesson Learned	Compliance Guidance Policy Team	Endorsed
Mixed Trust EACMS Authentication Lesson Learned	Compliance Guidance Policy Team	Endorsed
CIP-002-5.1: Grouping of BES Cyber Systems Lesson Learned	Compliance Guidance Policy Team	Endorsed
Vendor Access Management Lesson Learned	Compliance Guidance Policy Team	Endorsed
TPL-007-1: Transformer Thermal Impact Assessment	CCC Compliance Guidance Task Force	Endorsed
FAC-003-3 Standard Application Guide	MRO Standards Committee	Endorsed
CIP-002-5.1 Standard Application Guide	MRO Standards Committee	Endorsed
CIP-014-1 Requirement R1 Guideline	Compliance Guidance Policy Team	Endorsed for Inactive Reliability Standard
TOP-001-3: System Operating Limit Definition and Exceedance Clarification	CCC Compliance Guidance Task Force	Pending
FAC-008-3 Standard Application Guide	MRO Standards Committee	Pending
PER-005 Standard Application Guide	MRO Standards Committee	Declined Endorsement

Table A.2: Implementation Guidance Submittals		
Draft Reliability Standard Compliance Guidance for PER-005-2	CCC Compliance Guidance Task Force	Declined Endorsement
PRC-005-6 Standard Application Guide	MRO Standards Committee	Pending
PER-005 System Personnel Training Reference Document	MRO Standards Committee	Declined Endorsement
PRC-023: Determination and Application of Practical Relaying Loadability Ratings	Compliance Guidance Policy Team	Declined Endorsement
TPL-001-4 Standard Application Guide	MRO Standards Committee	Pending
Screening Criterion for Thermal Impact Assessment White Paper	CCC Compliance Guidance Task Force	Declined Endorsement
PRC-004-5(i) Standard Application Guide	MRO Standards Committee	Pending
TPL-001-4 Modeling Reference Document	North American Transmission Forum (NATF)	Pending
Transient Voltage Criteria Reference Document	NATF	Pending

Enforcement Metrics Highlights

Enforcement's 2016 goal to have more than 70 percent of issues of noncompliance be self-identified was met in 2016. The self-assessment and identification of noncompliance metric is used to compare the number of noncompliance discovered internally versus externally to promote self-assessment and internal identification of noncompliance. For self-identification of noncompliance in 2016, the threshold is 70 percent and the target is 75 percent. Enforcement met the threshold and target for this goal, closing the year at an 87 percent self-identification rate.

The ERO Enterprise has continued to promote timely mitigation of noncompliance with over 99 percent of noncompliance discovered before 2013 having completed Mitigation Plans or mitigating activities, reducing risk to the BPS. The ERO Enterprise successfully met its mitigation targets for noncompliance discovered in 2014 and 2015 by ensuring at least 90 percent of noncompliance discovered in 2014 and 75 percent of noncompliance discovered in 2015 have been mitigated. Significantly, these target goals were both exceeded, with almost 99 percent of 2014 noncompliance and 90 percent of 2015 noncompliance being mitigated. Enforcement also met its goal of having 100 percent of Notices of Penalty approved by FERC.

Mitigation Completion

- Ninety-nine percent of violations discovered before 2015 have completed Mitigation Plans or mitigating activities. There are 66 violations discovered in 2014 and earlier with ongoing Mitigation Plans or mitigating activities with estimated completion dates in 2017. This represents about 0.7 percent of the total violations discovered in 2014 and earlier.

Caseload

- In the second half of 2016, there has been a substantial increase in the number of violations discovered. This is likely due to new Reliability Standards that became enforceable on July 1, 2016. The increase is largely made up of CIP Version 5, MOD-025-2, and PRC-019-2 noncompliance. Of the 1,181 noncompliance discovered in 2016, there were 487 violations of requirements that were newly enforceable in July 2016. Noncompliance in the second half of the year was double the number of violations reported in the first half. The increase has shown no signs of abatement and may continue in the first half of 2017.
- The ongoing use of CEs throughout the ERO Enterprise, combined with the influx of noncompliance discovered in the second half of 2016, has contributed to the average age of noncompliance in Q4 2016 dropping to less than 8 months. The average age has not been this low since 2013. Typically, noncompliance has a relatively consistent average age in the ERO Enterprise inventory of approximately 10 to 11 months.
- Eighty-one percent of the ERO Enterprise noncompliance inventory is less than one year old, and only seven percent is over two years old.
- FRCC, NPCC, RF, and Texas RE have completed processing of all violations with discovery dates before 2014.
- There are 49 pre-2014 violations remaining to be processed across MRO, SERC, SPP RE, and WECC. Seventeen of these violations are from federal entities.
- At the beginning of 2016, there were 368 federal entity violations that were on hold pending the result of a case before the DC Circuit Court of Appeals. Federal violations have been prioritized in 2016, and there are only 17 still needing to be processed, less than five percent of the initial total.

Self-Assessment and Self-Identification of Noncompliance

- Registered entities self-identified, on average, approximately 87 percent of new instances of noncompliance in 2016.[28]

Vegetation-Related Transmission Outages

The ERO Enterprise monitors all categories of vegetation-related outages that could pose a risk to the reliability of the transmission system and, although the overall number of vegetation contacts remains small, there has been an increase in the number of contacts. The ERO Enterprise will continue to monitor these matters and enforce any noncompliance appropriately. Data regarding vegetation-related outages in 2015 is available in the 2015 Annual Vegetation-Related Transmission Outage Report.

In Q2 2016, the REs reported ten vegetation-related outages to NERC, all of which were Category 3[29] contacts, which is an increase of three from the previously reported quarter. All but one of the outages occurred on 230 kV lines. In nine of the outages, trees fell into transmission lines during severe weather conditions. The remaining

[28] Self-identification includes noncompliance discovered through Self-Reports, Self-Certifications, and Periodic Data Reporting. The percentage does not include self-identification before a Compliance Audit or Spot Check.

[29] Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW.

outage involved a dead tree located outside of the right-of-way (ROW) falling into the line. There has been no Category 1A[30] or 1B[31] grow-in outages in 2016. For more information, see Figure A.12.

Enforcement Metrics – Additional Information

Mitigation Completion Status

The mitigation of the oldest violations (dating from 2013 and earlier) is over 99 percent complete. NERC enforcement discusses the progress on the outstanding noncompliance with the REs on a semi-monthly basis, continues to monitor these violations, and makes them a priority for mitigation completion. Additionally, registered entities continue to mitigate noncompliance discovered in 2014 and 2015 at a satisfactory rate. NERC enforcement has accomplished both targets in 2016.

Table A.3: Mitigation Completion Status

Timeframe	Required Mitigation	Ongoing	Progress Toward Goal	Threshold	Target	Progress Since Last Quarter
2013 and Older	8544	56	99.34%	100%	100%	0.14%
2014	964	10	98.96%	85%	90%	1.86%
2015	728	66	90.93%	70%	75%	8.49%

Age of Noncompliance in ERO Inventory

This graph shows the age of noncompliance from all non-federal entities and only federal entities beyond the November 2014 cutoff.[32] There has been almost no change in the distribution of the percentages from the prior quarter.

[30] Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside or outside of the ROW.

[31] Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside or outside of the ROW.

[32] The U.S. Court of Appeals for the District of Columbia Circuit ruled that monetary penalties could not be imposed on federal entities. All previously reported federal entity violations were formerly on hold pending the court's decision. The pre-court case federal entity violations and the post-court case violations have been separated because routine processing was interrupted.

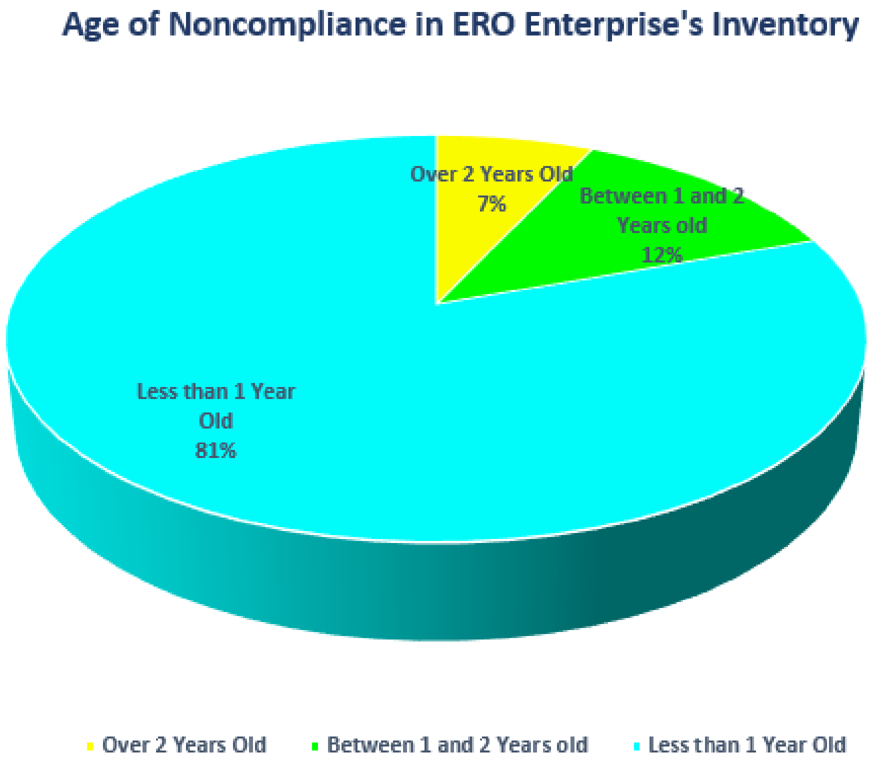


Figure A.2: Age of Noncompliance in the ERO Enterprise Inventory

Average Age of Noncompliance in the ERO Enterprise Inventory

As mentioned previously, the average age of noncompliance continues to lower for two reasons. The first is the increase in discovered and submitted violations. Newly enforceable Reliability Standards that have gone into effect as of July 1, 2016, have resulted in a substantial increase in noncompliance discovered and submitted to NERC as registered entities attempt to comply. The second reason is that the average age of noncompliance is also being affected by the increased usage of CEs as a disposition method. CEs represent approximately half of all noncompliance processed in 2016, and their processing periods tend to be shorter.

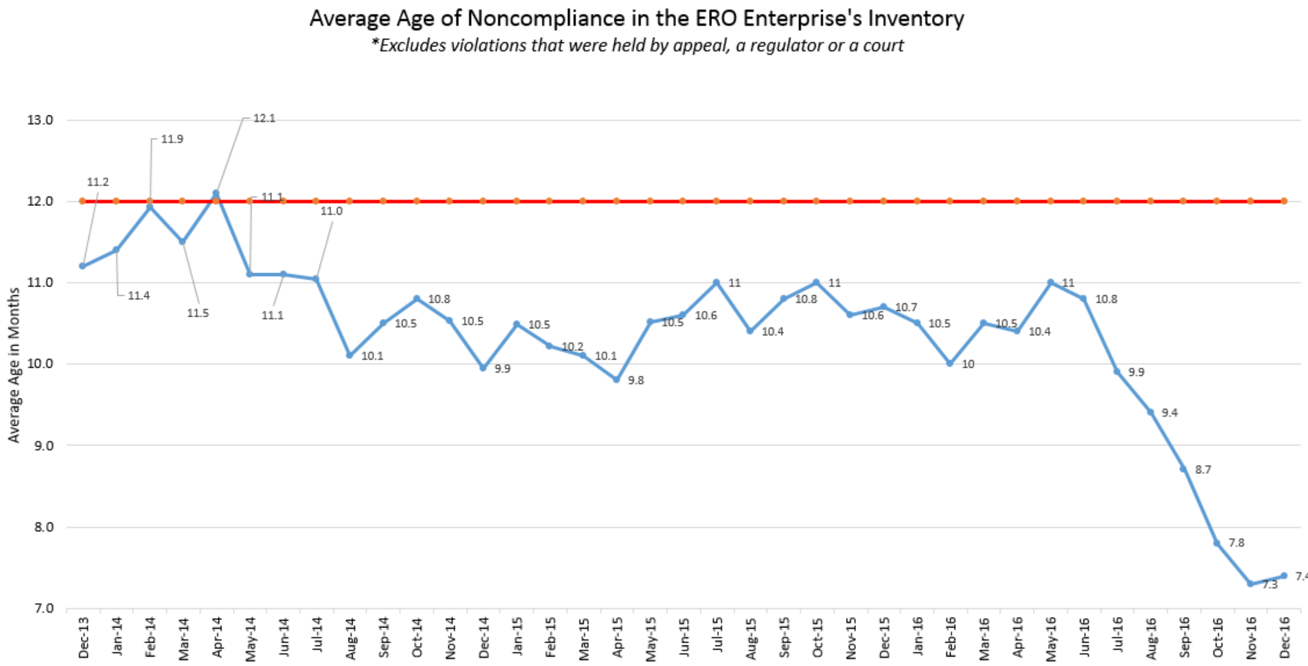


Figure A.3: Average Age of Noncompliance in the ERO Enterprise Inventory

Number of New Noncompliance Discovered in 2016

The number of new noncompliance continued to increase in Q4 2016. This increase in new noncompliance is due to the July 1, 2016, enforceable date for several new Reliability Standards. Approximately 41 percent of the new violations discovered in 2016 were from these Reliability Standards. There were 238 new noncompliance that fell under CIP Version 5. There were 103 newly reported noncompliance with MOD-025-2, 74 of PRC-024-2, and 61 of PRC-019-2—each of these Reliability Standards also went into effect July 1, 2016.

Table A.4: Noncompliance Discovered in 2016

Discovery Month	FRCC	MRO	NPCC	RF	SERC	SPP RE	Texas RE	WECC	Total
January		1	3	16	7	4	9	8	**48**
February		5	4	19	29	2	7	10	**76**
March		3	7	11	5	4	4	12	**46**
April	1	1	8	14	21	8	4	9	**66**
May	1	1	5	15	2	9	40	9	**82**
June		4	3	10	7	6	11	15	**56**
July	3	8	4	30	17	18	7	20	**107**
August	4	4	2	28	38	9	8	20	**113**
September	4	6	4	12	34	94	12	29	**195**
October	2	3	12	74	25	5	9	43	**173**
November	3		6	19	23	2	29	30	**112**
December			1	22	34	1	5	51	**114**
Total	**18**	**36**	**59**	**270**	**242**	**162**	**145**	**256**	**1188**

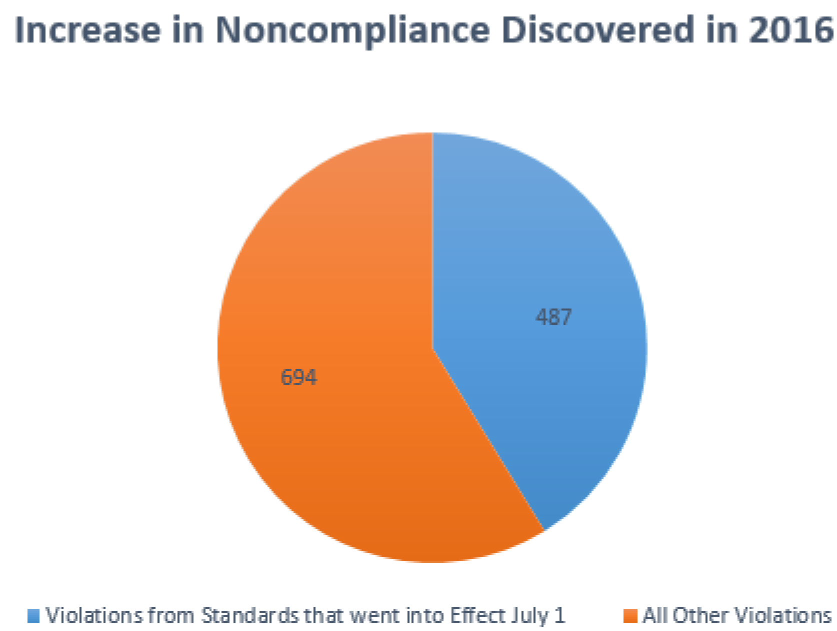


Figure A.4: Percentage of 2016 Newly Discovered Noncompliance with a July 1, 2016, Enforceable Date

Number of Instances of Noncompliance Discovered Internally Versus Externally

The percentage of internally discovered noncompliance has increased over the last several years. Q4 2016 has returned to the long-term average of internally discovered noncompliance over externally discovered. Figure A.5 breaks down internal and external discovery method by year—Figure A.6 over the last six quarters.

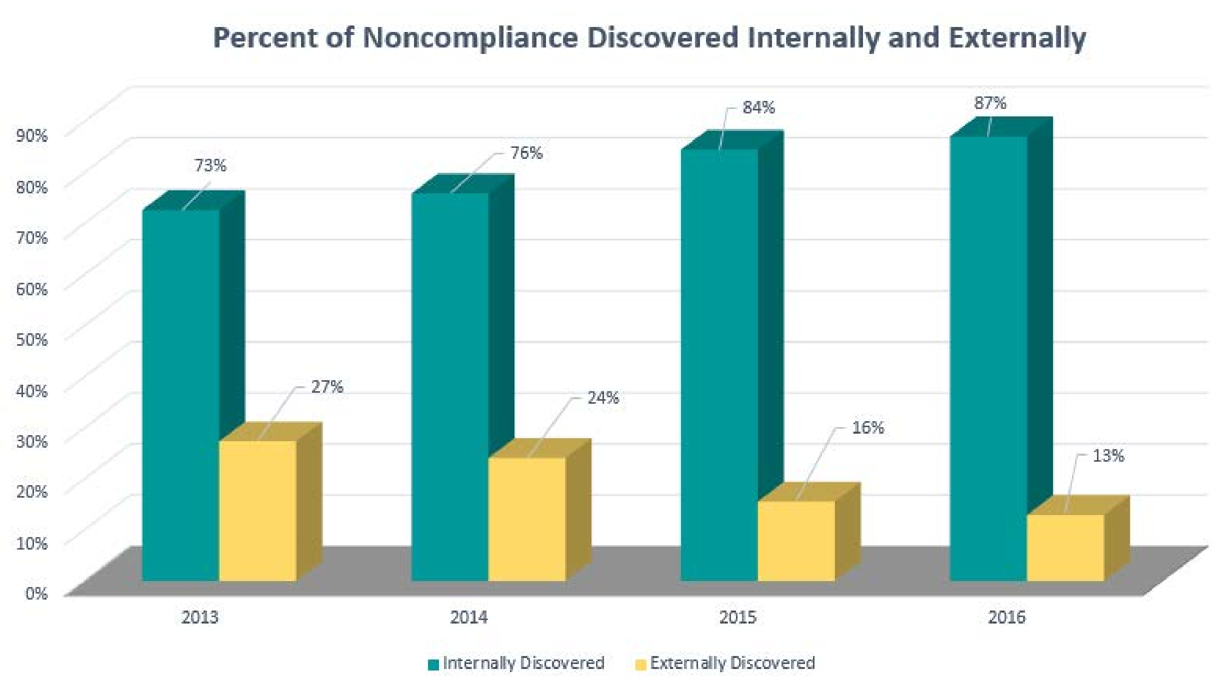


Figure A.5: Percentage of Noncompliance Discovered Internally and Externally by Year

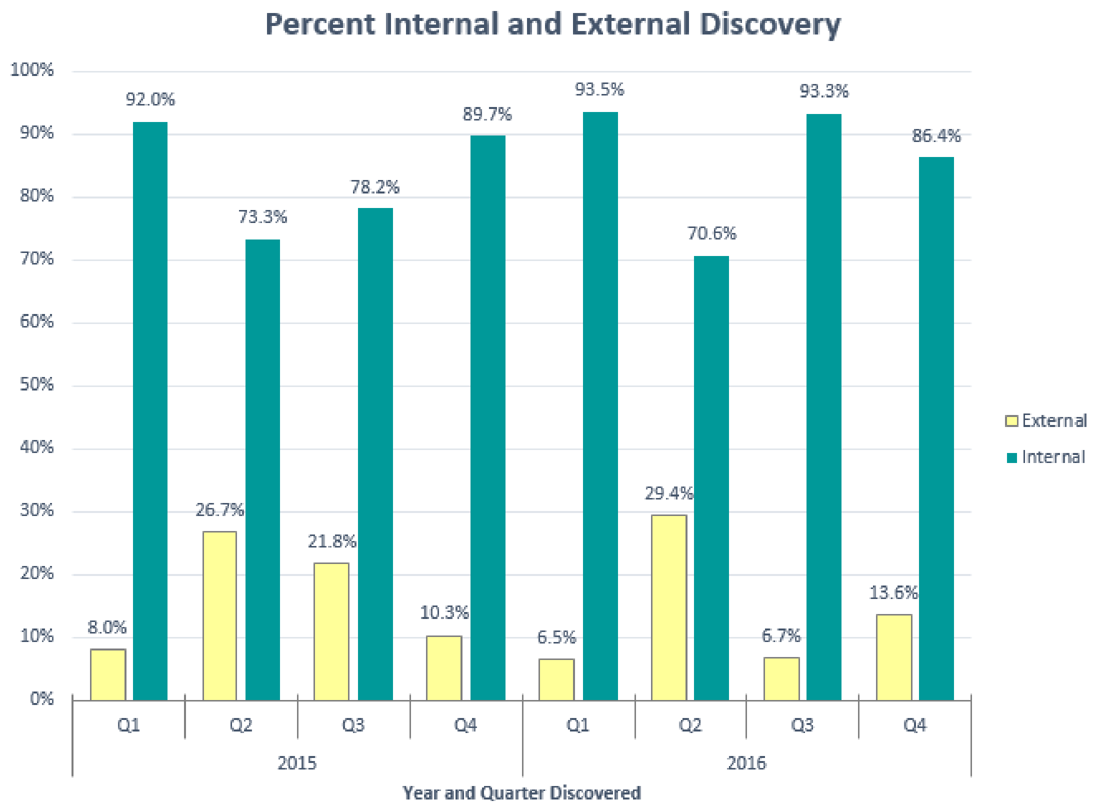


Figure A.6: Percentage of Noncompliance Discovered Internally and Externally by Quarter

Contribution of the Self-Logging Program to Posted CEs

In Q4 2016, the percentage of self-logged CEs continues to hold steady at 13 percent, consistent with Q3 2016.

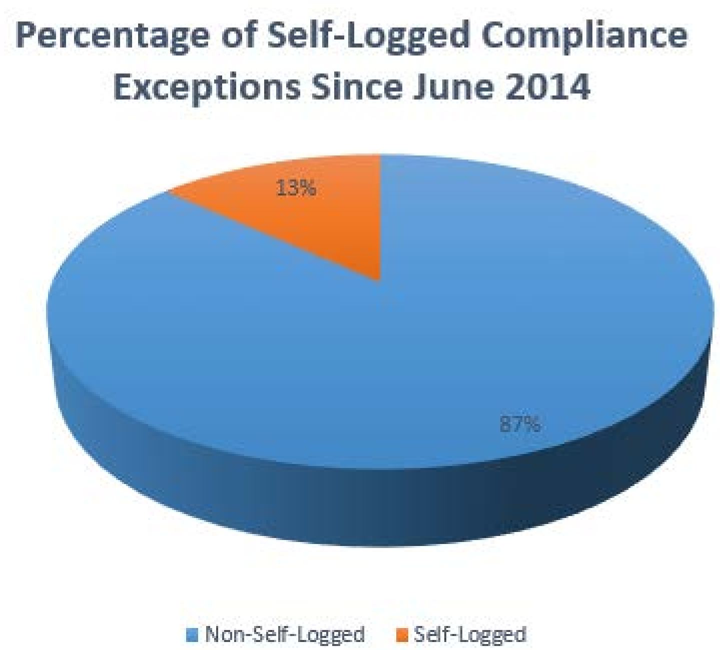


Figure A.7: Percentage of Self-Logged CEs since June 2014

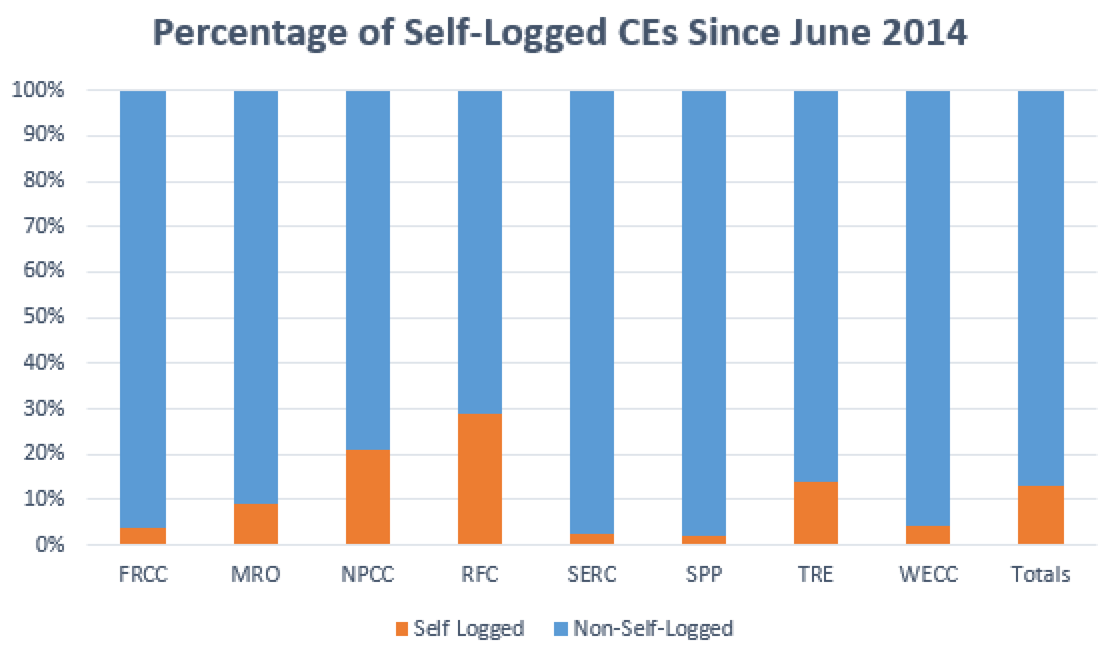


Figure A.8: Percentage of Self-Logged CEs since June 2014 by RE

Use of CEs for Minimal Risk Issues

The ERO Enterprise continues to use CEs successfully to process a majority of minimal risk noncompliance efficiently. In Q4 2016, the REs used the program to provide 62 percent of their minimal risk noncompliance to NERC as CEs.

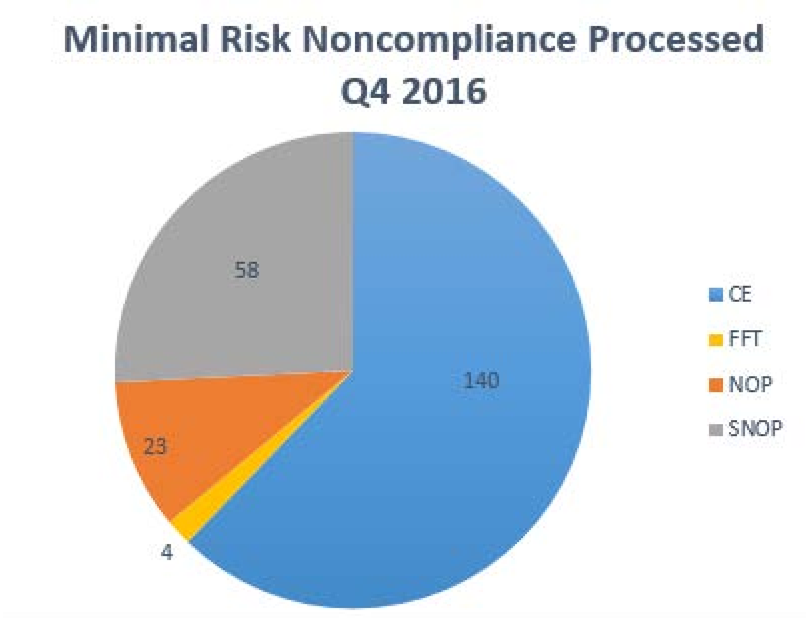


Figure A.9: Minimal Risk Noncompliance Processed in Q4 2016

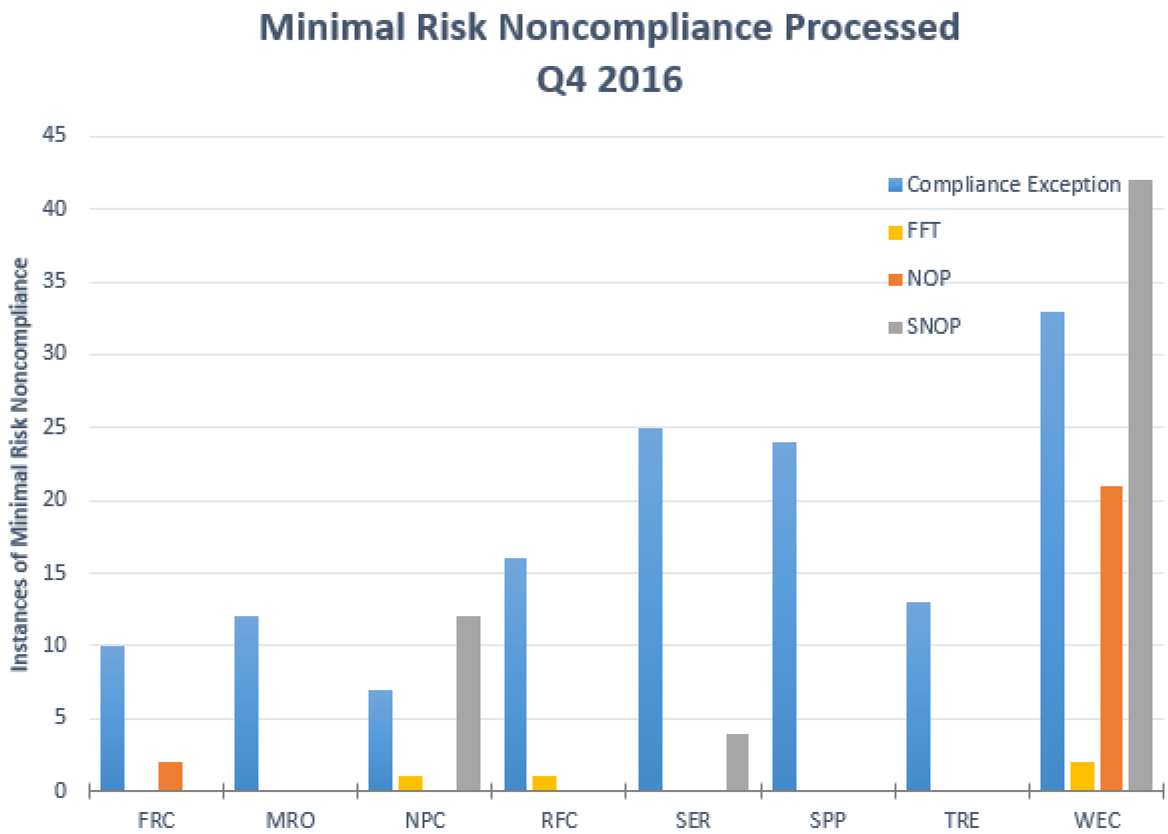


Figure A.10: Minimal Risk Noncompliance Processed in Q4 2016 by Region

Most Violated Reliability Standards Discovered in 2016

In addition to having the highest frequency of noncompliance in 2016, CIP-004, CIP-005, CIP-006, and CIP-007 are also among the most violated historically. PRC-005, FAC-008, and VAR-002 are also commonly violated. Several new Reliability Standards have joined the list in Q4 2016, MOD-025, PRC-024, and PRC-019, as a result of newly enforceable Reliability Standards in 2016.

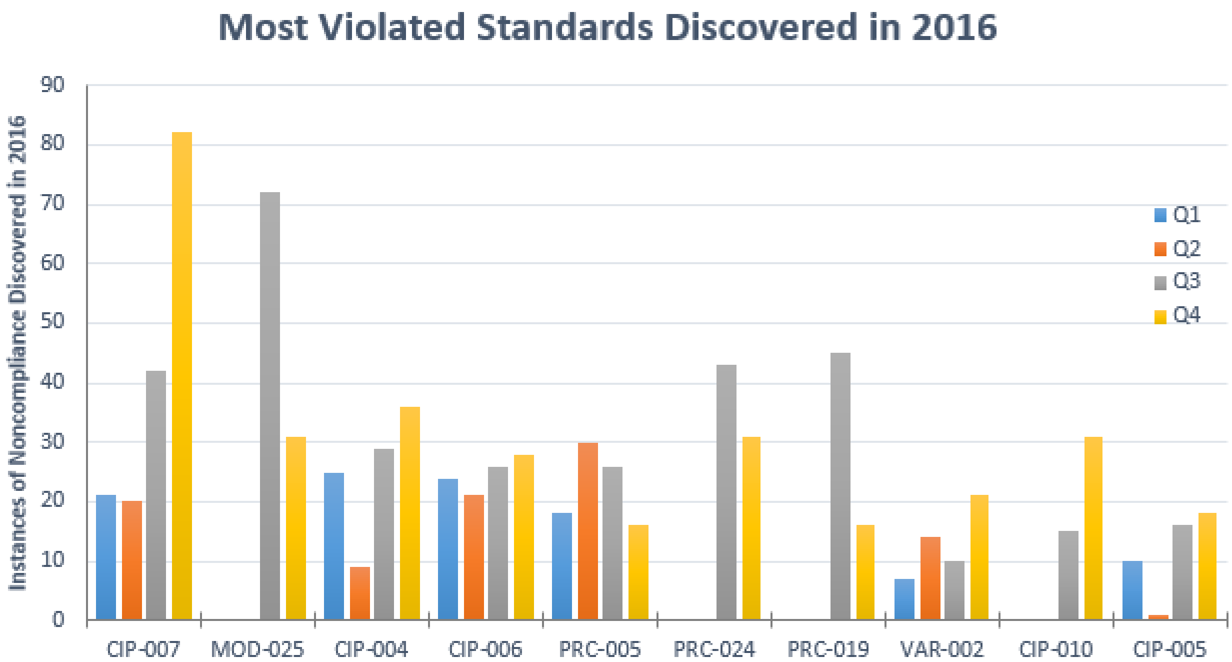
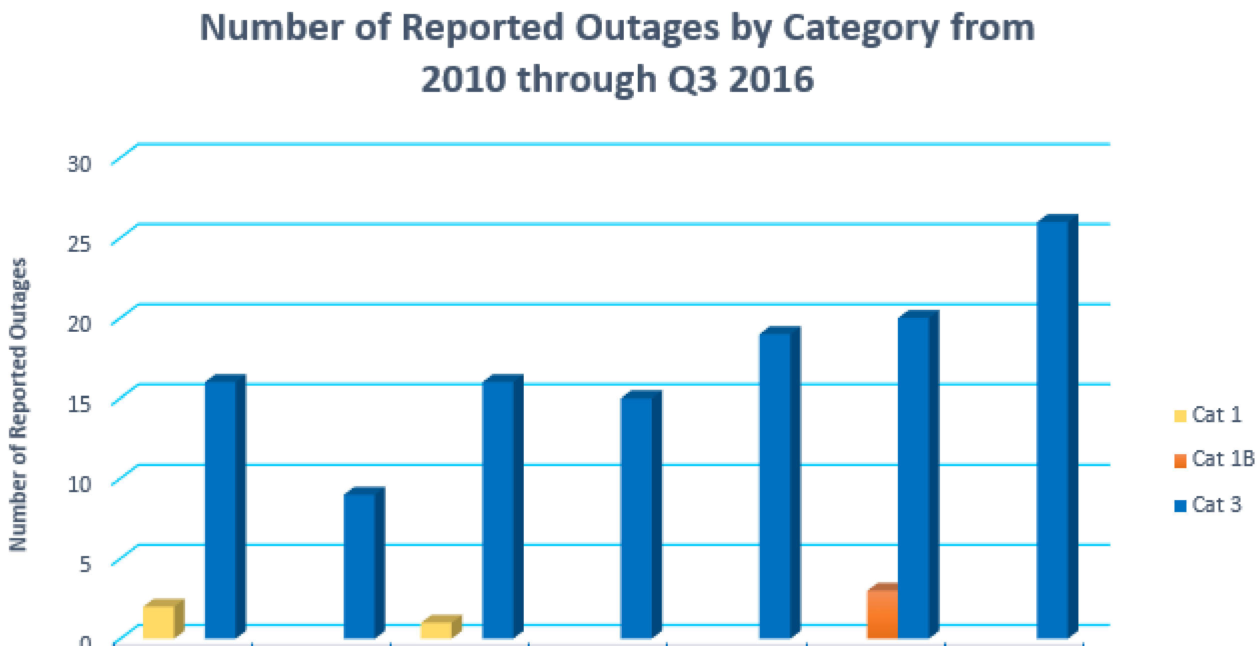


Figure A.11: Most Violated Reliability Standards Discovered in 2016 by Quarter

Vegetation Management

The number of outages caused by vegetation rose in 2016. In the first three quarters of 2016, there were 26 outages due to vegetation contacts. Though the number of outages was higher than 2015 (23), there were no Category 1 or 1B outages in 2016. All of the vegetation contacts in 2016 were Category 3 outages.



	2010	2011	2012	2013	2014	2015	2016
Cat 1	2		1				
Cat 1B						3	
Cat 3	16	9	16	15	19	20	26

Figure A.12: Vegetation-Related Outages by Category from 2010 through Q3 2016

Serious Risk Violations

Since 2010, NERC has gathered data on and regularly monitored violations posing a serious risk to the reliability of the BPS. Noncompliance posing a serious or substantial risk to the BPS is not considered a Confirmed Violation until filed with FERC. The risk determination is not final until review and approval by NERC. Therefore, Figure A.13 reflects violations that have been NERC-approved and filed with FERC. As shown in Figure A.13, serious risk violations have declined over time and continue to account for a small portion of all instances of noncompliance reviewed by the ERO Enterprise.

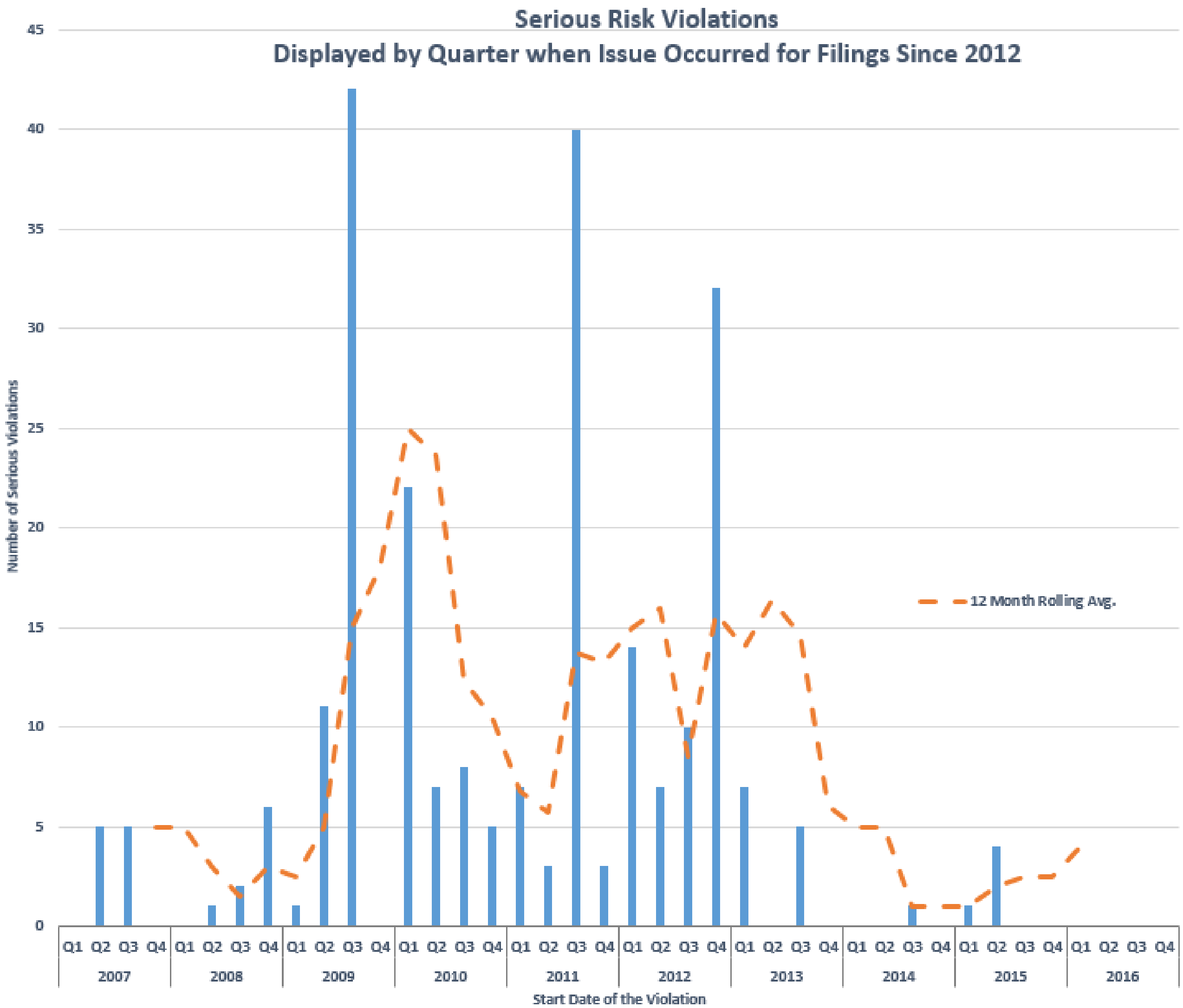


Figure A.13: Serious Risk Violations by Start Date

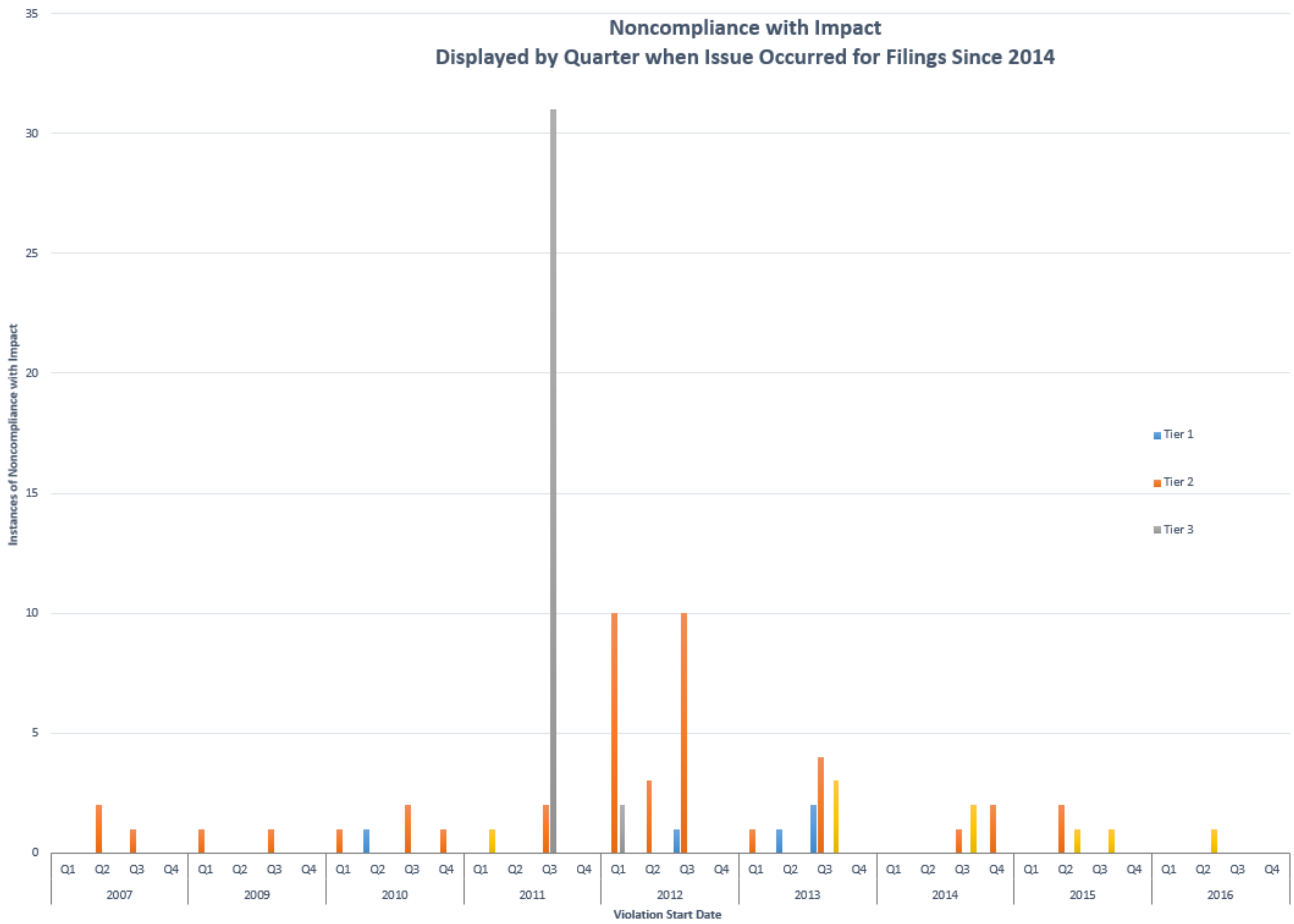


Figure A.14: Noncompliance Posing an Impact to the BES by Quarter

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Essential Reliability Services and the Evolving Bulk-Power System -- Primary Frequency Response	)))	**Docket No. RM16-6-000**

COMMENTS OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
IN RESPONSE TO NOTICE OF PROPOSED RULEMAKING

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January 24, 2017

TABLE OF CONTENTS

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Essential Reliability Services and the Evolving Bulk-Power System -- Primary Frequency Response	**)))**	**Docket No. RM16-6-000**

COMMENTS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IN RESPONSE TO NOTICE OF PROPOSED RULEMAKING

The North American Electric Reliability Corporation ("NERC") hereby provides comments on the Federal Energy Regulatory Commission ("Commission") Notice of Proposed Rulemaking ("NOPR") regarding proposed revisions to the Commission's rules and regulations on primary frequency response.[1] The NOPR follows the Commission's Notice of Inquiry ("NOI")[2] regarding essential reliability services and proposes to impose primary frequency response requirements on newly interconnecting generation through revisions to the *pro forma* Large Generator Interconnection Agreement ("LGIA") and the *pro forma* Small Generator Interconnection Agreement ("SGIA"). The NOPR also requests comment whether the Commission should direct modifications to NERC Reliability Standards or revise the *pro forma* Open Access Transmission Tariff ("OATT") to impose primary frequency response requirements on existing resources.

As described below and detailed in NERC's NOI Comments, revisions to the *pro forma* LGIA and *pro forma* SGIA to support primary frequency response capability would be

[1] *Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response*, 157 FERC ¶ 61,122 (2016) ("NOPR").
[2] *Essential Reliability Services and Evolving Bulk-Power System–Primary Frequency Response*, 154 FERC ¶ 61,117 (2016) ("NOI").

consistent with NERC reliability assessments.[3] As discussed in those assessments, NERC has determined that the rapidly changing resource mix may reduce the level of available frequency response. The proposed revisions to the *pro forma* LGIA and the *pro forma* SGIA are consistent with NERC's determination in the assessments and help ensure sufficient frequency response. As discussed in its comments to the NOI, however, it is still too soon for NERC to determine whether it is necessary or appropriate to revise Reliability Standards to impose primary frequency response requirements on existing generation resources. NERC is continuing to examine frequency response issues closely and is on schedule to address the adequacy of primary frequency response resources and potential enhancements to Reliability Standards by no later than the July 1, 2018 deadline for the informational filing on NERC Reliability Standard BAL-003-1.1 -- Frequency Response and Frequency Bias Setting.[4] These comments describe the status of various NERC frequency response projects.[5] NERC remains committed to examining primary frequency response as an essential reliability service.

I. COMMUNICATIONS

Notices and communications with respect to these comments may be addressed to the

[3] *Comments of North American Electric Reliability Corporation*, Docket No. RM16-6-000 (filed Apr. 25, 2016) ("NOI Comments"). *See also*, NERC's Essential Reliability Services Task Force Measures Framework Report ("Framework Report") and Abstract Document ("Abstract") (issued December 17, 2015), NERC's State of Reliability Report for 2015, the NERC Operating Committee's *Reliability Guideline: Primary Frequency Control* (issued December 15, 2015), the NERC State of Reliability 2015 Report ("2015 SOR"), NERC's 2015 Long-Term Reliability Assessment, and NERC's 2016 Long-Term Reliability Assessment.

[4] In Order No. 794, the Commission directed NERC to submit reports within three months after two years of operating experience once BAL-003-1 R1 becomes effective. *Frequency Response and Frequency Bias Setting Reliability Standard*, Order No. 794, 146 FERC ¶ 61,024 (2014). The reports must address: (1) an evaluation of the use of the linear regression methodology to calculate frequency response; and (2) the availability of resources for applicable entities to meet the Frequency Response Obligation. The reports will also include any recommended revisions to Reliability Standards (such as changes to impose frequency response obligations on generation.

[5] NERC will continue to share any results of its research and analysis, as appropriate and available.

following:[6]

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II. COMMENTS

The Commission's proposed revisions to the *pro forma* LGIA and the *pro forma* SGIA are consistent with NERC reliability assessments regarding a potential decline in frequency response resources due to the changing resource mix.[7] Primary frequency response is an essential reliability service, particularly during events, islanding, and system restoration.[8] Although NERC continues to examine frequency response issues,[9] NERC agrees that the NOPR's proposed revisions to the *pro forma* LGIA and the *pro forma* SGIA could aid in mitigating the risk of declining frequency responsive resources, helping to ensure that sufficient frequency response capability remains ready to respond and support bulk power system ("BPS")

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[6] 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, to allow the inclusion of more than two persons on the service list in this proceeding.

[7] *See e.g.*, NOPR, at P 24; *and* NOI Comments, at Section IV.A.

[8] Frequency response is the ability of a system or elements of the system to react or respond to a change in system frequency and is the metric traditionally used to describe interconnection performance in arresting decline and stabilizing frequency after a loss of resources or load. Primary frequency response is one component for frequency response and is measured by relating the size of the resource lost to the resulting net change in system frequency. Primary frequency response arises from automatic generator governor response, load response, and other mechanisms. *See*, NERC Glossary (explaining that Frequency Response is expressed as the sum of change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hz (MW/0.1 Hz)) and Framework Report.

[9] *See*, NOI Comments, at Section IV.B.

reliability and system restoration.

The Commission's proposed revisions would supplement NERC's current Reliability Standard requirements and ongoing assessments of the potential need for additional Reliability Standard requirements. NERC Reliability Standard BAL-003-1.1 currently requires Balancing Authorities ("BAs") and Frequency Response Sharing Groups ("FRSGs") to take action to ensure sufficient frequency response. On December 1, 2016, all requirements in BAL-003-1.1 became enforceable. Consistent with Commission directive, NERC also continues to examine whether it is necessary or appropriate to revise its Reliability Standards to impose primary frequency response requirements on existing resources. With the support of industry subject matter experts, NERC continues to study frequency response issues and develop guidance to enhance frequency response capability where possible. As discussed in the NOPR and NOI Comments, these projects include, for example, NERC's 2015 industry Advisory, Operating Committee Reliability Guideline: Primary Frequency Control ("OC Guidelines"), and Forward-Looking Frequency Response Assessment.[10] NERC remains on schedule to address the adequacy of primary frequency response resources and potential enhancements to Reliability Standards in the BAL-003-1.1 informational filing. These initiatives and studies demonstrate NERC's commitment to identifying and demonstrating the need for frequency response *capability* at the resource level, as well as frequency response *performance* at the system level.

10 *See e.g.*, NOPR, at PP 14-16; *and* NOI Comments, at Section IV.B.

A. The NOPR's proposed revisions to the *pro forma* LGIA and the *pro forma* SGIA are consistent with NERC reliability assessments.

The NOPR proposes to revise the *pro forma* LGIA and the *pro forma* SGIA to require that newly interconnecting generation install, maintain, and operate primary frequency response capability under certain minimum operating conditions consistent with NERC OC Guidelines.[11]

The Commission's proposed revisions to the *pro forma* interconnection agreements are consistent with the results of recent NERC reliability assessment recommendations. As detailed in NERC's NOI Comments, NERC has determined that increasing levels of non-synchronous resources installed without controls that enable frequency response capability, coupled with retirement of conventional resources that have traditionally provided primary frequency response, has contributed to the decline in primary frequency response.[12] Moreover, a changing resource mix will further alter the dispatch of resources and combinations of resources across the daily and seasonal demand spectrum, potentially resulting in systems operating states where frequency response capability could be diminished unless a sufficient amount of frequency responsive capacity is included in the dispatch.[13]

To mitigate this risk, the NOPR's proposed revisions would apply measurable, clear requirements, such as those anticipated in the NOI Comments, to newly interconnecting synchronous and non-synchronous resources in a fair and equitable manner that should lead to tighter control and frequency stability.[14] In addition, the NOPR's proposed minimum operating conditions should help ensure that frequency response capability is installed as well as available and ready to respond, regardless of the mix of resources in the dispatch. Such requirements for

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[11] NOPR, at PP 43-56 (describing the Commission's proposals in detail).

[12] NOI Comments, at Section IV.A.

[13] *Id.*

[14] NOI Comments, at Section IV.C.1.

the capability of "timely and sustained response to frequency deviations"[15] should promote reliability and help avoid a scenario where the transforming resource mix reduces frequency response capability.

In addition, NERC supports the Commission's proposal to incorporate NERC's OC Guidelines regarding droop and deadband settings and coordination between governor and plant control systems within Sections 9.6.4 and 1.8.4 of the modified *pro forma* LGIA and *pro forma* SGIA, respectively.[16] NERC also notes that the Commission should consider modifying the *pro forma* LGIA and the *pro forma* SGIA to reflect the OC Guideline recommendation that deadbands be implemented without a step to the droop curve, i.e. once outside the deadband the change in output starts from zero and then increases proportionally to interconnection frequency error. As explained in NERC's NOI Comments, the OC Guidelines reflect the most advanced set of continent-wide best practices and information available in support of frequency response capability.[17] NERC also supports the Commission's proposal that primary frequency response capability be tested and confirmed during commissioning.

NERC further suggests the Commission consider requiring Interconnection Customers, as defined in the *pro forma* LGIA and the *pro forma* SGIA, to also provide to relevant BAs, as requested, (i) the status and settings of the governor or equivalent controls and plant level controls; and (ii) situations where the Interconnection Customer needs to operate its generation facility with the governor or equivalent controls and plant level controls not in service. The BA is the entity that has a compliance obligation for providing frequency response. Therefore, it needs to know the status and settings of the governor or equivalent controls and plant level

15 NOPR, at P 44.
16 NOPR, at PP 52-53.
17 NOPR, at P 31 (describing NERC's NOI Comments).

controls in order to assess whether there is an appropriate amount of frequency reserve available. Providing this information would support BA and FRSG efforts to help ensure sufficient frequency response and their compliance with Reliability Standard BAL-003-1.1.

NERC agrees with the Commission's proposal not to impose a generic headroom requirement at this time. NERC believes there are two facets to helping ensure adequate primary frequency response for an interconnection. First, you must have generation resources that have installed frequency response capability. Second, you must have a generation dispatch that results in an adequate amount of unloaded frequency responsive generation (headroom) or other frequency responsive resources connected to the system at all times. The proposed revisions to the *pro forma* LGIA and *pro forma* SGIA that require primary frequency response capability on newly connected generation will address the first facet. NERC Reliability Standard BAL-003-1.1 currently addresses the second facet. BAs are the responsible entities for ensuring load and generation balancing. BAs are obligated through BAL-003-1.1 to ensure they have adequate headroom on their operating generation or other frequency responsive resources available within their real-time generation dispatch to meet their frequency response obligation. This approach would require headroom on every generator.

B. NERC is continuing to study whether Reliability Standards should impose frequency response requirements on existing resources.

In proposing revisions to the *pro forma* LGIA and the *pro forma* SGIA, the Commission also requests comment whether it should direct modifications to NERC Reliability Standards or the *pro forma* OATT to impose primary frequency response requirements on existing resources.[18]

[18] NOPR, at P 57.

As discussed in NERC's NOI Comments, it is too soon after the implementation of Reliability Standard BAL-003-1.1 to determine whether additional primary frequency response performance or capability requirements for existing resources are necessary or appropriate for inclusion in NERC Reliability Standards. Effective 2016, Reliability Standard BAL-003-1.1, Requirement R1, requires that BAs and FRSGs achieve an annual frequency response measure ("FRM") to meet their frequency response obligation ("FRO") ensuring sufficient frequency response performance in the interconnection.[19] Consistent with Commission directive,[20] NERC has already begun investigating how BAL-003-1.1 may be influencing frequency response performance and capability and whether enhancements to Reliability Standards are necessary.

NERC continues to analyze frequency response issues with the help of stakeholders developing approaches to support frequency response capability. Various NERC initiatives to study and support primary frequency response capability are discussed in NERC's NOI Comments.[21] NERC appreciates this opportunity to provide an update on such projects and explain how they are contributing to greater understanding regarding frequency response needs across the BPS. Since its NOI Comments, NERC has (i) co-hosted a well-attended frequency response workshop with the North American Generator Forum ("NAGF") at NERC's Washington, D.C. Office; (ii) continued work on the Forward-Looking Frequency Response Assessment described in NERC's NOI Comments; (iii) initiated frequency response generator surveys including hosting a survey webinar with support from the NERC OC's Resource Subcommittee ("RS") and NAGF; (iv) begun work on an FRSG Guideline; and (v) begun

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19 The interconnection frequency response obligation ("IFRO") is calculated on an annual basis to set a required level of response to ensure that frequency excursions caused by loss of large-scale resources do not cause load shedding by under-frequency load shedding programs. Interconnection-level primary frequency response performance is measured against the IFRO to ensure adequate primary frequency controls.

20 *See* Order No. 794 at P 3.

21 *See e.g.,* NOI Comments, at Section IV.B.

analysis of frequency response calculations under BAL-003-1.1. More detail on these initiatives is immediately below.

First, on June 22 and 23, 2016, the NERC RS and NAGF co-hosted a Frequency Response Workshop to discuss the importance of frequency response, the history of frequency response initiatives, potential issues, and relevant NERC Reliability Standards. The workshop provided NERC, industry, and Commission staff an opportunity to ask questions about primary frequency response capabilities upon integration of a changing resource mix. Questions included, for example, how technologies and markets might adapt to enhance frequency response. This discussion has helped inform NERC and stakeholder studies, such as the Forward-Looking Frequency Response Assessment.

Second, throughout 2016, NERC has continued working on the Forward-Looking Frequency Response Assessment. The assessment analyzes the potential effects of the changing resource mix on primary frequency response performance over a five-year period. Studies under the assessment include potential scenarios and sensitivities associated with the projected future change in resource mix. NERC is using an interconnection-wide dynamic case[22] to develop the five-year assessment on frequency response performance. Efforts remain on track for an interim study report in 2017.

In addition, at the September 2016 OC meeting, the OC approved an RS initiative to survey generators to support analysis of frequency response in the Eastern, Western, and Quebec Interconnections and enhance dynamic modeling. On December 8, 2016, NERC hosted a webinar, with support from the RS and NAGF, regarding the then-planned generator surveys. These surveys should enhance information gathering regarding primary frequency response

[22] The Eastern Interconnection Reliability Assessment Group – Multi-Regional Modeling Working Group (MMWG) creates these interconnection-wide base-cases.

resource capability at an interconnection level and Generator Owner and Generator Operator efforts to obtain primary frequency response capability. Data gathered through this project should be materially beneficial to NERC's frequency response studies.

The OC continued to work on frequency response issues during its December 2016 meeting. Notably, the OC approved the modification of its Operating Reserve Management Guideline to include guidelines for Frequency Response Sharing Groups.

Further, NERC continues its analysis of BAL-003-1.1 calculations, including IFRO and FRO and the use of median versus linear regression methods to determine frequency response obligations and frequency response measurements.

NERC will publicly post the results of its studies as available and continue actively working with stakeholders to develop guidance as analysis continues.

III. CONCLUSION

Wherefore, for the reasons stated above and in NERC's NOI Comments, NERC supports the NOPR. In addition, NERC appreciates this opportunity to affirm its commitment to examining primary frequency response issues and to provide the status of various NERC frequency response projects. NERC will continue to analyze the impacts of the changing resource mix on frequency response and evaluate whether additional frequency response requirements are necessary for existing resources. NERC will report on this analysis in its informational filing on NERC Reliability Standard BAL-003-1.1 due July 1, 2018 and will continue to apprise the public on frequency response-related findings as they develop.

Respectfully submitted,

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Date: January 24, 2017

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service lists compiled by the Secretary in Docket No. RM16-6-000.

Dated at Washington, DC this 24th day of January, 2017.

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators	**)** **)** **)** **)**	**Docket Nos. RM16-23-000** **AD16-20-000**

COMMENTS OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
IN RESPONSE TO NOTICE OF PROPOSED RULEMAKING

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators	**))))**	**Docket Nos. RM16-23-000 AD16-20-000**

COMMENTS OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
IN RESPONSE TO NOTICE OF PROPOSED RULEMAKING

The North American Electric Reliability Corporation ("NERC") hereby provides comments on the Federal Energy Regulatory Commission's ("FERC" or "Commission") Notice of Proposed Rulemaking ("NOPR") issued on November 17, 2016 in the above-referenced proceeding.[1] In this NOPR, the Commission proposes to amend its regulations under the Federal Power Act to remove barriers to the participation of electric storage resources and distributed energy resource aggregators in the capacity, energy, and ancillary service markets operated by regional transmission organizations and independent system operators (organized wholesale electric markets). The Commission also seeks comment regarding "whether and to what extent the Commission-approved Glossary of Terms and associated Reliability Standards…may create barriers to the participation of electric storage resources or other non-synchronous technologies in the organized wholesale electric markets."[2]

NERC is the Electric Reliability Organization ("ERO") designated under Section 215 of the Federal Power Act to develop and enforce Reliability Standards for the reliable operation of

[1] Notice of Proposed Rulemaking , *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 157 FERC ¶ 61,121 (Nov. 17, 2016) (hereinafter the "NOPR").

[2] NOPR at P 52.

the North American Bulk-Power System, subject to Commission approval.[3] As the ERO, NERC submits that Reliability Standards, including the terms used in those standards and defined in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary"), would create no barriers to the participation of electric storage resources or other non-synchronous technologies in the organized wholesale electric markets.

I. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[4]

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II. COMMENTS

The body of NERC Reliability Standards work together as an integrated whole to protect and preserve the reliability of the Bulk-Power System. Each Reliability Standard is developed through an open and inclusive American National Standards Institute-accredited process, approved by stakeholders, adopted by the NERC Board, and submitted for Commission approval

[3] The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the Federal Power Act (16 U.S.C. § 824o) on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006).

[4] 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 (2016), to allow the inclusion of more than two persons on the service list in this proceeding.

prior to becoming effective in the United States.[5] To promote consistency throughout the Reliability Standards, NERC maintains the NERC Glossary, which contains definitions of terms that have been approved through NERC's process and are used in one or more Reliability Standards.[6] As the Commission noted in Order No. 693, "The terms defined in the glossary have an important role in establishing consistent understanding of the Reliability Standards Requirements and implementation."[7]

Reliability Standards fall within one of 14 standard families that address different aspects of reliable operations. One standard family in particular, the Resource and Demand Balancing ("BAL") Reliability Standards, is of particular relevance to the Commission's NOPR. The BAL Reliability Standards address balancing resources and demand to maintain Interconnection frequency within prescribed limits, which is essential for reliably operating an electric power system. As discussed herein, while the BAL Reliability Standards are associated with the dispatch of generation on the Bulk-Power System, they provide entities with the flexibility to meet the performance-based requirements of those standards. As such, these Reliability Standards would not create a barrier to the participation of electric storage resources or other non-synchronous technologies in the organized wholesale electric markets.

Three BAL standards in particular work together to ensure that resources are used in conjunction with one another in furtherance of reliable operations:

- BAL-001-2 (Real Power Balancing Control Performance)

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[5] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual. 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.

[6] The NERC Glossary is available on NERC's website at http://www.nerc.com/files/Glossary_of_Terms.pdf.

[7] Order No. 693, *Mandatory Reliability Standards for the Bulk-Power System*, FERC Stats. & Regs. ¶ 31,242 ("Order No. 693") at P 1893, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

- BAL-002-1 (Disturbance Control Performance), to be retired by approved BAL-002-2 (Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event)
- BAL-003-1.1 (Frequency Response and Frequency Bias Setting)

Reliability Standard BAL-001-2 is designed to ensure that Interconnection frequency is maintained within predefined limits by requiring responsible entities to operate such that certain long-term and short-term system performance measures are met.[8] Approved Reliability Standard BAL-002-2 is designed to ensure that the responsible entity is prepared to balance resources and demand by requiring the maintenance of adequate reserves and deployment of those reserves to return its Area Control Error ("ACE")[9] to defined values following a qualifying event.[10] Reliability Standard BAL-003-1.1 is designed to ensure that each of the interconnections has sufficient frequency response to maintain Interconnection frequency within predefined bounds and guard against underfrequency load-shedding due to an event in the interconnection.[11]

Each of these standards contains performance-based requirements, meaning that the requirements define the reliability outcome to be achieved without prescribing the specific

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[8] Reliability Standard BAL-001-2 – Real Power Balancing Control Performance was approved by the Commission in 2015 in Order No. 810. *See* Order No. 810, *Real Power Balancing Control Performance Reliability Standard*, 151 FERC ¶ 61,048 (2015). The standard is available at http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf.

[9] Area Control Error is defined in the NERC Glossary as:

> The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias, correction for meter error, and Automatic Time Error Correction (ATEC), if operating in the ATEC mode. ATEC is only applicable to Balancing Authorities in the Western Interconnection.

[10] On January 19, 2017, the Commission issued Order No. 835 approving Reliability Standard BAL-002-2 with directives for future modifications. *See* Order No. 835, *Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event Reliability Standard*, 158 FERC ¶ 61,030 (2017). Under the approved implementation plan, Reliability Standard BAL-002-2 will become effective on the first day of the first calendar quarter that is six months after the date of Commission approval.

[11] Reliability Standard BAL-003-1 was approved by the Commission in 2014 in Order No. 794. *See* Order No. 794, *Frequency Response and Frequency Bias Setting Reliability Standard*, 146 FERC ¶ 61,024 (2014). Currently-effective errata version BAL-003-1.1 was approved in 2015. *See N. Am. Electric Reliability Corp.*, Docket No. RD15-6-000 (Nov. 13, 2015) (delegated letter order). The standard is available at http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-1.1.pdf.

methods that must be used to achieve it. Further, each of these standards are technology neutral. To demonstrate, BAL-001-2 requires each Balancing Authority to operate such that its ACE is greater than or equal to 100 percent for the applicable interconnection in which it operates for each preceding 12 consecutive calendar month period, evaluated monthly. This standard would not affect the specific output of any individual resource; rather, it evaluates the overall ability of the Balancing Authority to balance resources and demand. Likewise, approved Reliability Standard BAL-002-2 requires each Balancing Authority to recover ACE following the unexpected loss of a resource in its area. This standard does not specify the manner a Balancing Authority must use to balance resources and demand. As such, these standards would not create a barrier to the participation of electric storage resources or other non-synchronous technologies.

In addition to the relevant Reliability Standards, NERC has also examined the NERC Glossary to determine whether any defined terms could potentially pose a barrier to the participation of electric storage resources or other non-synchronous technologies. Two defined terms, "Spinning Reserve"[12] and "Operating Reserve-Spinning,"[13] specifically reference

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[12] The term Spinning Reserve is defined as "[u]nloaded generation that is synchronized and ready to serve additional demand." The Commission approved the definition of this term in 2007 in Order No. 693. *See* Order No. 693 at P 1887.

[13] The term Operating Reserve – Spinning is defined as:

The portion of Operating Reserve consisting of:

- Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or
- Load fully removable from the system within the Disturbance Recovery Period following the contingency event.

A related term, Operating Reserve- Supplemental, is defined as:

The portion of Operating Reserve consisting of:

- Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event; or
- Load fully removable from the system within the Disturbance Recovery Period following the contingency event.

The Commission approved the definitions of these terms in Order No. 693.

generation that is synchronized to the system. However, NERC does not view the existence of these terms in the Glossary as potentially posing a barrier to the participation of electric storage resources or other non-synchronous technologies in the organized wholesale electric markets for the following reasons. The term "Spinning Reserve" is not used in its defined (i.e. capitalized) or commonly understood (i.e. non-capitalized) meaning in any U.S. mandatory and enforceable Reliability Standard that establishes reserve obligations for registered entities.[14] With respect to the term "Operating Reserve-Spinning," NERC notes that the Commission has approved the retirement of the only continent-wide Reliability Standard that uses this term, Reliability Standard BAL-002-1. Requirement R2.3 of this standard provides that each responsible entity shall specify its Contingency Reserve policies, including the permissible mix of Operating Reserve-Spinning and Operating Reserve-Supplemental that may be included in Contingency Reserve. As noted above, the approved successor standard BAL-002-2 uses a performance-based approach to ensuring that each responsible entity maintains adequate reserves to recover ACE following the unexpected loss of a resource in its area.

The other currently enforceable standard in which the term "Operating Reserve – Spinning" is used, regional Reliability Standard BAL-002-WECC-2, is the subject of a recently approved interpretation.[15] This interpretation adds the following clarification to the standard regarding the resources that may be used as "Operating Reserve-Spinning":

> [N]on-traditional resources, including electric storage facilities, may qualify as "Operating Reserve-Spinning" so long as they meet the technical and performance requirements in [BAL-002-WECC-2] Requirement R2 (i.e. that the reserves must be immediately and automatically responsive to frequency deviations through the action

[14] While the term is used in its non-capitalized form in Reliability Standard EOP-002-3.1 – Capacity and Energy Emergencies, it is only referenced in the report that a Balancing Authority must file when declaring an Energy Emergency Alert 3.

[15] *N. Am. Elec. Reliability Corp.*, Docket No. RD17-3-000 (Jan. 24, 2017) (delegated letter order).

> of a control system and capable of fully responding within ten minutes.)[16]

This interpretation is entirely consistent with the Commission's Order No. 789 approving the standard.[17] In light of FERC's order and this recently approved interpretation, NERC does not view the use of the term "Operating Reserve-Spinning" in the regional standard as potentially posing a barrier to the participation of electric storage resources that meet the regional standard performance requirements. Should the WECC regional standard be retired, NERC would evaluate whether to retire this term using its standard development process.

In conclusion, the NERC Reliability Standards that are associated with the dispatch of generation on the Bulk-Power System provide entities with flexibility to meet the performance-based requirements of those standards. As such, these Reliability Standards would not create a barrier to the participation of electric storage resources or other non-synchronous technologies in the organized wholesale electric markets.

III. <u>CONCLUSION</u>

NERC respectfully requests that the Commission accept these comments in response to the Notice of Proposed Rulemaking.

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[16] *Joint Petition of the North American Electric Reliability Corporation and Western Electricity Coordinating Council for Approval of Interpretation of Regional Reliability Standard BAL-002-WECC-2a*, Docket No. RD17-3-000 (Nov. 9, 2016).

[17] *Id.* at 7-8. See also, Order No. 789, *Regional Reliability Standard BAL-002-WECC-2 – Contingency Reserve*, 145 FERC ¶ 61,141 (2013) at P 48.

Respectfully submitted,

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Dated: February 13, 2017

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service lists compiled by the Secretary in Docket Nos. RM16-23-000 and AD16-20-000.

Dated at Washington, DC this 13th day of February, 2017.

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	))	**Docket No. RR15-4-00_**

INFORMATIONAL FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

The North American Electric Reliability Corporation ("NERC") hereby submits this informational filing in accordance with the Federal Energy Regulatory Commission's ("Commission" or "FERC") October 15, 2015 Order ("October 15 Order").[1] In the October 15 Order, the Commission accepted NERC's proposal to remove the load-serving entity ("LSE") as a functional registration category from the NERC Compliance Registry ("NCR").[2] The Commission accepted that the risks posed by the elimination of the LSE functional registration category are likely to be minimal because load data will continue to be available.[3] Specifically, the Commission found that balancing authorities, planners and other affected entities continue to have access to necessary data to estimate demand and energy forecast in areas where LSEs are deregistered.[4]

[1] *North American Electric Reliability Corp.*, 153 FERC ¶ 61,024 (2015).

[2] This informational filing does not provide an update on sub-set lists of NERC Reliability Standards. *See North American Electric Reliability Corp.*, 150 FERC ¶ 61,213 (2015). To date, NERC has received one request for the application of a sub-set list of Reliability Standards and reduced set of compliance obligations. As NERC receives and examines additional requests in the future, NERC will assess whether there are any consistent criteria or system characteristics among such applicants that define a group of lower risk registered entities qualifying for such reduced compliance obligations.

[3] October 15 Order at P 20.

[4] October 15 Order at P 23.

In the October 15 Order, the Commission directed NERC to submit an informational filing addressing two separate directives within 15 months of the order.[5] First, the Commission directed NERC to provide an update on the process of transferring commercial-related requirements covered by retired NERC Reliability Standard INT-011, the only Reliability Standard solely applicable to LSEs, to commercial standards issued by the North American Energy Standards Board ("NAESB"). NAESB develops and promotes standards to ensure a seamless marketplace for wholesale and retail natural gas and electricity. Second, the Commission directed NERC to conduct a follow-up analysis to assess whether the removal of LSEs affects transmission operators and balancing authorities' ability to conduct accurate next-day studies.

NERC respectfully requests that the Commission to accept this informational filing in response to the Commission's directives in the October 15 Order which affirms the commercial role of LSEs and the minimal impact of their removal from the NCR on the reliability of the Bulk Power System.

[5] October 15 Order at Ordering Paragraph (B).

TABLE OF CONTENTS

I. Completion of Coordination with NAESB

Prior to the issuance of the October 15 Order, NERC and NAESB discussed whether the retirement of any NERC Reliability Standards solely applicable to LSEs warranted the development of such a NAESB standard. NAESB identified NERC Reliability Standard INT-011-1 as a candidate for a NAESB standard. Requirement R1 of INT-011-1 required LSEs to submit a request for interchange for point-to-point transmission service for intra-balancing authority area transfers unless the transfer is included in an alternative congestion management procedure.

In October 2016, NAESB submitted Version 003.1 of its Wholesale Electric Quadrant ("WEQ") Business Practice Standards to FERC. In that filing to FERC, NAESB noted that it developed modifications to its WEQ-004 Coordinate Interchange Business Practice Standards incorporating language from INT-011. The modifications to the WEQ-004 Coordinate Interchange Business Practice Standards incorporate a requirement for LSEs related to the submittal of a request for interchange for certain intra-balancing authority transactions. Specifically, WEQ-004-1 now requires the submittal of a request for interchange, in addition to transactions between a source and sink balancing authority, for point-to-point intra-balancing authority transitions not already represented by alternative congestion management tools. Therefore, NERC's retirement of Reliability Standard INT-011-1 and NAESB's development of WEQ-004-1 confirms the continued commercial accountability of LSEs in interchange transactions.

II. Accuracy of Next-Day Studies

In the October 15 Order, the Commission directed NERC to perform a follow-up analysis to examine whether transmission operators and balancing authorities affected by the removal of the LSE functional registration category remain able to perform reasonably accurate next-day studies.[6] The Commission specifically directed NERC to do the following:

(a) identify a representative sample of affected transmission operators and balancing authorities;

(b) determine the extent to which next-day studies match or differ from real-time results; and,

(c) determine, if there are any differences, whether those differences are attributable to the removal of the LSE functional registration category.

A. Representative Sample of Affected Transmission Operators and Balancing Authorities

In response to the Commission's directive, NERC examined the following three Balancing Authorities affected by the removal of LSEs – Duke Energy Carolinas, ERCOT and PacifiCorp. In each of the footprints where LSEs were deactivated or deregistered, the affected load was small and represented less than 5% of the total load. Therefore, in order to evaluate the impact of deregistering LSEs on next-day study methodologies, NERC selected Balancing Authorities with the greatest amount of affected load. Specifically, NERC selected three Balancing Authorities whose affected load represented more than 1.0% of total load in their respective footprints. NERC also selected BAs from three different interconnections. Below is a table listing all load affected by the deregistration of LSEs organized by Balancing Authority.

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[6] October 15 Order at P 40.

Load Served by Deactivated LSEs

Balancing Authority	Total 2013 BA Load (MW)	% of 2013 Balancing Authority Load Served by LSEs
CAISO	48,967	0.70
Duke Energy Carolinas	19,471	3.39
ERCOT	67,998	3.29
MISO	114,333	0.20
NYISO	33,725	0.22
PacifiCorp	12,700	2.64
PJM	155,553	0.10
Public Service Company of New Mexico	2,710	1.62
Southwest Power Pool	52,247	0.11
Louisville Gas and Electric & Kentucky Utilities ("LG&E/KU")	7,207	2.78

Load Served by Deregistered LSEs

Balancing Authority	Aggregated, Individual 2013 Peak Load (MW)	% of Balancing Authority Load Served by LSEs
ERCOT	2,238	3.37
PacifiCorp	317	2.56
California ISO	359	0.80
Public Service Company of New Mexico	44	1.70
Duke Energy Carolina	661	3.39
LG&E/KU	200	2.76
New York ISO	113	0.33
Midwest ISO	230	0.19
PJM	178	0.13

B. Next-Day Study Methods

The objective of next-day studies is to allow system operators to prepare for real-time operations. Next-day studies consist of several inputs including topology (i.e., planned and/or forced equipment outages), generator unit commitment, and load forecast data (i.e., prediction of system load for a given footprint). Planners typically receive equipment outage information from the owners and operators of such equipment. For example, generator owners and generator operators supply generation outage data and transmission owners and operators supply transmission outage data. Planners examine load forecast data for any given Balancing Authority Area ("BAA") footprint. For purposes of next-day studies, the relevant load forecasts used by planners are short-term or day-ahead load forecasts. Balancing Authority planners are responsible for developing these short-term forecasts for scheduling and dispatching generation units. Load forecast data can also be analyzed for smaller sub-regions (i.e., at the Transmission Operator level within a given BAA). The Balancing Authorities examined in this informational filing also operate as the Transmission Operators. Since planners' load forecasting methodologies vary across BAA footprints, NERC outlines the approach used by each of the affected Balancing Authorities identified by NERC in the preceding section.

1. Load Forecasting in ERCOT

ERCOT's short and mid-term load forecast models use historical telemetered boundary data representing data captured at metering points on a four-second basis. ERCOT supplements the short-term and mid-term load forecasts with weather variables described herein. The relevant load forecast for ERCOT's next-day studies is its Mid-Term Load Forecasting ("MTLF") Seven-Day Load Forecast. Weather is the primary variable or source of error for any short-term load forecast.[7] A change in temperature, wind speed or even precipitation affects electricity demand. To account for the weather variable, ERCOT examines two inputs: (a) hourly forecasted weather parameters for weather stations within weather zones (updated at least once per hour); and (b) training information based on historical hourly integrated weather zone loads. ERCOT uses the MTLF to predict hourly loads for the next 168 hours (seven days) based on current weather forecast parameters within each weather zone. ERCOT's implementation and configuration of its MTLF utilizes a "self-training" mode that allows ERCOT to review historical load data and to retrain the MTLF algorithm. ERCOT performs this analysis itself and does not rely upon LSEs for this operational MTLF forecast.

ERCOT's Long-Term Load Forecast ("LTLF") model differs from the MTLF in that the LTLF incorporates forecasted economic variables to account for the growth in ERCOT's forecasted demand given the longer period covered by this forecast. Unlike the MTLF, LSEs can inform the LTLF by assisting planners to assess load growth for the long-term horizon. The LTLF is an hourly forecast for the next 10 years for each weather zone. ERCOT aggregates these forecasts to create the ERCOT total forecast.

2. Duke Energy

Duke Energy Carolinas ("DEC") develops an hourly forecast of DEC's BAA load for a seven-day horizon for use in its next-day studies. This load forecast uses historical BAA load information extracted from the DEC energy accounting systems and weather history, in addition to a forecast of system average temperature and dew point. Like ERCOT, this historical BAA load information represents meter data aggregating generation minus interchange or load leaving DEC's Balancing Authority footprint. DEC gathers the weather data (actual and forecast) input

[7] *See* ERCOT Protocol Section 3.12.1, Seven-Day Load Forecast.

from weather stations close to load. DEC personnel maintain internal load forecasting models using a third-party application called Metrix.

To supplement the internal forecasting process, DEC also uses an external load forecasting service called Tesla. A blending mechanism tracks the accuracy of each model over time and provides a blended forecast using separate weightings for each hour of the day based on recent performance. In addition, each model creates two forecasts using two weather forecasts, one from the National Weather Service Model Output Statistics ("MOS"), and one from Duke internal meteorologists ("DUK"). DEC uses the same program that blends the Metrix and Tesla forecasts to blend the MOS and DUK forecasts to provide a single forecast.

DEC Unit Commitment personnel are responsible for selecting from among the available forecast versions and making adjustments to peak, valley, or shape as they deem appropriate based on their experience. DEC updates the forecast at least once per day. The update frequency depends on system conditions at the time.

3. PacifiCorp

PacifiCorp's BAAs also prepare short-term load forecasts based on historical BAA load data captured at meters as well as future weather forecasts. This methodology examines historical real-time metering data as captured every four seconds. This metering data represents net generation minus net interchange. A forecast group refines this data and blends weather and day of the week components into the forecast. PacifiCorp also conducts after the fact verification of load forecasts with inputs from merchants and LSEs.

C. Load Forecasting Error

Since LSEs do not provide inputs for the determination of short-term load forecasts, any differences identified in load forecasting error between 2015 and 2016 could not be attributed to any identifiable loss of load data from LSEs. Nonetheless, NERC requested that ERCOT, Duke Energy Carolinas, PacifiCorp and LG&E/KU compare load forecast accuracy in 2015 (the year in which LSEs were removed as a functional registration category) to load forecast accuracy in 2016 to determine whether there are any significant differences in load forecast accuracy. NERC proposed that the Balancing Authorities selected for this informational filing compare load forecasting accuracy in the aggregate for 2015 versus 2016 in order to minimize the large weather impact fluctuations on short-term forecasting. Below are the error percentages from each of the selected Balancing Authorities.

1. <u>ERCOT</u>

ERCOT's Mean Absolute Percentage Error ("MAPE") for calendar year 2015 is 2.9%. The MAPE for 1/1/2016 – 10/31/2016 is 2.6%. These values are not weather-adjusted, meaning that they represent the total ("true") error in the forecast (includes weather error). ERCOT does not use weather-adjusted forecasts when reporting forecast error nor are the values available. Weather adjusted errors would be much lower than non-weather adjusted errors.

2. <u>Duke Energy Carolinas</u>

DEC's day-ahead MAPE forecasting error for January - October 2015 was 2.89%. DEC's day-ahead load forecast MAPE for January - October 2016 was 2.84%. These values are not weather-adjusted, and thus include weather error as a normal factor in load forecasting.

3. <u>PacifiCorp</u>

Below, PacifiCorp provides the aggregate forecast error percentages based on the day-ahead forecast submitted to Peak Reliability by PacifiCorp in 2015 and in 2016.

	Forecast Error (%)	
Balancing Authority Area	**2015**	**2016**
PacifiCorp East	4.40	3.80
PacifiCorp West	4.60	4.70

III. Conclusion

In three of the Balancing Authorities with the largest percentage of deactivated and deregistered LSEs, the calculation of next-day studies does not require input from former LSEs. Therefore, these Balancing Authorities cannot attribute the identified changes to load forecasting error to the removal of LSEs from the NCR. NERC respectfully requests that the Commission accept this informational filing.

Respectfully submitted,

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Date: January 17, 2017

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 17th day of January 2017.

/s/ Nina H. Jenkins-Johnston

Nina H. Jenkins-Johnston

Counsel for North American Electric Reliability Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Foundation for Resilient Societies	**)**	**Docket No. AD17-9-000**

COMMENTS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IN OPPOSITION TO PETITION FOR RULEMAKING

The North American Electric Reliability Corporation ("NERC") hereby provides comments in opposition to the Foundation for Resilient Societies ("Resilient Societies") Petition for Rulemaking to Require an Enhanced Reliability Standard to Detect, Report, Mitigate, and Remove Malware from the Bulk-Power System ("the Petition"), filed with the Federal Energy Regulatory Commission ("Commission") under Rule 207 of the Commission's Rules of Practice and Procedure in the above-captioned docket.[1] The Petition requests that the Commission direct NERC to develop a Reliability Standard that would require Responsible Entities[2] to detect, report, mitigate, and remove malware that could affect BES Cyber Systems and file the Reliability Standard within 90 days of the order directing development.[3]

NERC respectfully requests the Commission deny the Petition. NERC appreciates the risk that malware poses to the Bulk-Power System ("BPS") and uses its many reliability tools to mitigate this risk. As discussed below, NERC's enforceable Reliability Standards, current standard development activity, and other cyber security efforts adequately address the threats, vulnerabilities, and risks associated with malware detailed in the Petition. A new Reliability

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[1] *The Commission's Rules of Practice and Procedure*, 18 C.F.R. § 385.207(a).

[2] The Critical Infrastructure Protection Reliability Standards refer to the Functional Entities to which the standards apply as "Responsible Entities." Responsible Entities include Balancing Authorities, Reliability Coordinators, Transmission Owners, Transmission Operators, Generation Owners, Generation Operators, and certain Distribution Providers.

[3] *Petition for Rulemaking to Require an Enhanced Reliability Standard to Detect, Report, Mitigate, and Remove Malware from the Bulk-Power System*, Docket No. AD17-9-000 (filed Jan. 13, 2017) (refiled Jan. 19, 2017 with new docket caption) at p. 2.

Standard to address malware detection, reporting, mitigation, and removal is thus not necessary at this time.

NERC's currently enforceable suite of Critical Infrastructure Protection ("CIP") Reliability Standards employ a risk-based approach to Bulk Electric System ("BES") cyber security and mandate controls commensurate to the risk posed by threats and vulnerabilities to the reliable operation of the BES. Several of the Requirements within the CIP Reliability Standards require Responsible Entities to implement protections from the threat of malware. As with all of its standards, NERC continually evaluates whether additional protections are needed as it reviews the manner in which entities implement the required controls and the effectiveness of those controls.

Pursuant to Order Nos. 822 and 829, NERC is currently developing modifications to its CIP Reliability Standards that further enhance protections that mitigate the risks of malware.[4] Specifically, under Order No. 822, the Commission directed NERC to modify the CIP Reliability Standards to include additional protections for communications links and sensitive BES data communicated between BES Control Centers and to enhance protections for low impact BES Cyber Systems.[5] In Order No. 829, the Commission directed NERC to develop modifications to the CIP Reliability Standards to address supply chain risk management for industrial control system hardware, software, and computing and networking services associated with BES operations.[6] These ongoing development activities seek to strengthen the cyber security controls included in the CIP Reliability Standards and specifically target the threat of malware, as discussed below. Therefore, NERC's currently enforceable CIP Reliability Standards and ongoing development efforts address issues

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4 Order No. 822, *Revised Critical Infrastructure Protection Reliability Standards*, 154 FERC ¶ 61,037, 81 Fed. Reg. 4177 at paras. 3, 18, 64 (2016) ("Order No. 822"); Order No. 829, *Revised Critical Infrastructure Protection Reliability Standards*, 156 FERC ¶ 61,050, 81 Fed. Reg. 49,878 (2016) ("Order No. 829").

5 Order No. 822 at para. 3.

6 Order No. 829 at para. 1.

identified in the Petition, and the Commission does not need to direct NERC to revise the CIP Reliability Standards as requested in the Petition.

The Commission is currently reviewing the CIP Reliability Standards to determine whether additional modifications may be needed to address, among other things, risks associated with malware. Specifically, the Commission issued a Notice of Inquiry ("the NOI") seeking comment on the need for, and the possible effects of, modifications regarding "(1) separation between the Internet and BES Cyber Systems in Control Centers performing transmission operator functions; and (2) computer administration practices that prevent unauthorized programs from running, referred to as 'application whitelisting,' for cyber systems in Control Centers."[7] The Commission's review, coupled with NERC's continuous review of its Reliability Standards, should identify further revisions, if necessary, to the CIP Reliability Standards. Thus, the Commission should not direct NERC to develop Reliability Standards as outlined in the Petition prior to completing this review.

While NERC's CIP Reliability Standards provide the foundation for cyber security practices in the electric subsector, NERC's efforts to achieve effective cyber security extend beyond enforcement of mandatory Reliability Standards to enhancing industry's situational awareness, real-time communication, and prompt emergency response capabilities.[8] NERC operates the Electricity Information Sharing and Analysis Center ("E-ISAC"), which is a key component in providing these capabilities for the electric sector.[9] Among other things, E-ISAC collaborates with the Department of Energy ("DOE") on the Cybersecurity Risk Information Sharing Program, which provides timely, bi-

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[7] Notice of Inquiry, *Cyber Systems in Control Centers*, 156 FERC ¶ 61,051, 81 Fed. Reg. 49,641 (2016) at 2.

[8] *The Electricity Sector's Efforts to Respond to Cybersecurity Threats: Hearing before the Subcomm. On Energy of the H. Comm. On Energy and Commerce*, 115th Cong. § 5 (2017) (statement of Gerry W. Cauley, President and Chief Executive Officer, North American Electric Reliability Corporation), *available at* http://docs.house.gov/meetings/IF/IF03/20170201/105497/HHRG-115-IF03-Wstate-CauleyG-20170201.pdf.

[9] *Id.*

directional sharing of unclassified and classified threat information.[10] Moreover, NERC uses an alert system, called NERC Alerts, to communicate unclassified, sensitive information to industry and recommend entities take certain action to enhance their cyber security posture.[11] Since 2009, NERC has issued 41 cyber-related alerts, including an alert regarding the cyber security event in Ukraine in 2015.[12] NERC and industry also engage in security exercises that simulate crisis scenarios and allow industry to test incident response procedures. These security tools complement NERC's mandatory Reliability Standards to mitigate the cyber security risks to the electricity sector. Because these activities effectively address some of the concerns detailed in the Petition, the Commission should not direct NERC to incorporate them into mandatory Reliability Standards.

These comments are organized into three sections. Section I.A discusses the currently enforceable CIP Reliability Standards and their protections from malware. Section I.B provides an update on current standards development activities that address enhancements to the existing Reliability Standards. Finally, Section I.C highlights NERC's other cyber security activities that do not involve mandatory Reliability Standards.

I. COMMENTS

A. NERC currently has enforceable Reliability Standards that address cyber security threats from malware to the Bulk-Power System.

In the Petition, Resilient Societies notes that assets of the BPS are exposed to malware threats because the assets are connected to the public internet.[13] Resilient Societies further asserts cyber attackers can use implanted malware to steal passwords, conduct reconnaissance, extract data, remotely execute grid control, cause blackouts, and destroy equipment.[14]

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[10] *Id.* at 7.
[11] *Id.* at 8.
[12] *Id.* at 8-9.
[13] Petition at 2.
[14] *Id.*

As NERC commented in response to the NOI, the currently enforceable CIP Reliability Standards include a number of Requirements designed to mitigate the risks associated with Internet connectivity.[15] These Requirements mandate controls to mitigate the risks of remote access through the Internet, reduce the attack surface of Cyber Assets, help ensure Responsible Entities fix known software vulnerabilities that could be exploited by a malicious actor through the Internet, and help prevent and mitigate the threat of malicious code that may be introduced through Internet connections.[16] NERC and industry designed the currently enforceable CIP Reliability Standards to address the risk of malware detailed in the Petition. Therefore, NERC has current protections in place to mitigate the threat of malware to assets of the BPS.

Specifically, as detailed in the NOI Comments, the CIP Reliability Standards include several Requirements that address the risks associated with malware, including:

- *CIP-005-5, Requirement R1* requires entities to establish an Electronic Security Perimeter ("ESP") to control electronic access to BES Cyber Systems. An ESP is the "logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol." Among other things, Requirement R1 specifies that (1) all External Routable Connectivity, such as Internet connections, must go through an Electronic Access Point ("EAP") that requires inbound and outbound access permissions based on a valid need for granting such access; and (2) each EAP has one or more methods for detecting known or suspected malicious communications for both inbound and outbound communications.

- *CIP-005-5, Requirement R2* addresses the protections required for Interactive Remote Access, which is defined as "[u]ser access by a person employing a remote access client or other remote access technology using a routable protocol." Requirement R2 mitigates the risks of remote access through the Internet by requiring that entities (1) use an Intermediate System such that the Cyber Asset initiating Interactive Remote Access does not directly access an applicable Cyber Asset; (2) use encryption that terminates at an Intermediate System; and (3) require multi-factor authentication for all Interactive Remote Access sessions. These remote access protections would significantly impair a malicious actor's attempts to perpetrate the type of cyberattack carried out in Ukraine referenced in the NOI.

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[15] *Comments of the North American Electric Reliability Corporation in Response to Notice of Inquiry*, Docket No. RM16-18-000, at 5 (filed Sep. 26, 2016) ("NOI Comments").

[16] *See* NOI Comments at 5.

- *CIP-007-6, Requirement R1* requires entities to (1) enable only logical network accessible ports that have been determined to be needed by the Responsible Entity; and (2) protect against the use of unnecessary physical input/output ports used for network connectivity, console commands, or Removable Media. The controls help reduce the attack surface of Cyber Assets.

- *CIP-007-6, Requirement R2* requires entities to implement a patch management process for tracking, evaluating, and installing cybersecurity patches. This security control helps ensure that entities fix known software vulnerabilities that could be exploited by a malicious actor through the Internet.

- *CIP-007-6, Requirement R3* requires entities to (1) deploy methods to detect, deter, or prevent malicious code, and (2) mitigate the threat of detected malicious code. This Requirement helps prevent and mitigate the threat of malicious code that may be introduced through Internet connections.

- *CIP-010-2, Requirement R4, Attachment 1* addresses elements included in plans to manage Transient Cyber Assets and Removable Media. Among other things, Attachment 1 requires Responsible Entities to mitigate malicious code on Transient Cyber Assets and Removable Media prior to connecting to medium and high BES Cyber Systems. In addition, Attachment 1 requires Responsible Entities to mitigate the risk of vulnerabilities posed by unpatched software on Transient Cyber Assets. Through these Requirements, the CIP Reliability Standards help to prevent malware propagation to BES Cyber Systems through Transient Cyber Assets and Removable Media.

- *CIP-003-6, Requirement R2, Attachment 1 Section 4 and CIP-008-5, Requirement R1* address Reportable Cyber Security Incidents for low, medium, and high impact BES Cyber Systems. A Reportable Cyber Security Incident is defined as "[a] Cyber Security Incident that has compromised or disrupted one or more reliability tasks of a functional entity." Responsible Entities must report Reportable Cyber Security Incidents to the E-ISAC, which may include incidents related to malware. The E-ISAC would use its tools to share that information more broadly throughout the industry.

The CIP Reliability Standards promote allocation of resources to the highest risk areas. The currently enforceable CIP Reliability Standards incorporated principles from the National Institute of Standards and Technology Risk Management Framework to categorize and apply security controls.[17] The CIP Reliability Standards include categorization criteria based on the

[17] *See* Background, Reliability Standard CIP-002-5.1, at 3, *available at* http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=CIP-002-5.1a&title=Cyber%20Security%20%E2%80%94%20BES%20Cyber%20System%20Categorization&jurisdiction=United%20States.

impact of BES Cyber Systems to the reliable operation of the BES.[18] Based on the categorization, the CIP Reliability Standards require Responsible Entities to implement cyber security controls around the BES Cyber Systems that pose the greatest risk to the reliability of the BPS. Responsible Entities can therefore allocate resources appropriately based on the Requirements and risk.

The CIP Reliability Standards also support reliability by balancing cyber security with operational functionality. As outlined in the NOI Comments, "[t]he risk-based framework established in the CIP Reliability Standards seeks to balance the operational needs of responsible entities to have Internet connections to BES Cyber Systems in Control Centers with the security need to protect against Internet borne threats."[19] Data exchange, remote access, patch management, and transmission scheduling capabilities must run smoothly in order for the grid to operate reliably.[20] Therefore, the CIP Reliability Standards are designed to incorporate security practices into these operations without significantly reducing reliability.

The ERO Enterprise's compliance monitoring and enforcement program helps to ensure compliance with the Reliability Standards and continued assessment of the efficacy of the currently enforceable Reliability Standards. Prior to the July 1, 2016 enforceable date, NERC and the Regional Entities conducted extensive outreach to Responsible Entities to assist in the transition to the new version of the CIP Reliability Standards. Since July 1, 2016, the Regional Entities have conducted audits and other compliance monitoring activities assessing Responsible Entities' compliance, and the Commission has collaborated with NERC on additional audits of Responsible Entities. NERC addresses suggested modifications to the CIP Reliability Standards based on

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[18] *Id.* at 5.
[19] *See* NOI Comments at 4.
[20] *Id.* at 6-9.

observations during compliance monitoring and enforcement activities through the established standards development process.

B. NERC is developing revisions to its Reliability Standards that will strengthen cyber security, including mitigating risks associated with malware.

Resilient Societies claimed that CIP Reliability Standards do not provide malware protections for communications networks outside the ESP.[21] Further, Resilient Societies commented that the CIP Reliability Standards exempt assets containing low impact BES Cyber Systems from malware protection Requirements.[22] Finally, Resilient Societies asserted that vulnerabilities in cyber supply chains "provide pathways for both malware infection and firmware 'backdoors' into control systems."[23] As discussed below, however, consistent with Commission directives, NERC is currently developing modifications to its CIP Reliability Standards to address these issues, among others.

In response to directives in Order No. 822, NERC initiated a standards development project that addresses further malware protections for assets containing low impact BES Cyber Systems and protections for communications links and sensitive data communicated between BES Control Centers. The standards drafting team clarified electronic access controls and Requirements to mitigate introduction of malicious code from transient devices for assets containing low impact BES Cyber Systems in CIP-003-7, which was approved by the NERC Board of Trustees on February 9, 2017. In addition, the standards drafting team developed draft language on logical protections of communications links transmitting sensitive data between Control Centers of all impact levels (high, medium, and low) for industry comment. The protections extend beyond ESPs if the sensitive data traveled outside ESPs. The proposed revisions enhance protections in

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21 Petition at 12.
22 *Id.*
23 *Id.* at 10.

the CIP Reliability Standards by, among other things, helping to mitigate some the risks of the introduction of malware to BES Cyber Systems.

Additionally, NERC assembled a standards drafting team to address directives in Order No. 829 on mitigating cyber security risks in the supply chain. The draft Reliability Standard, CIP-013-1, requires Responsible Entities to develop and periodically review a supply chain risk management plan that addresses four security objectives: 1) software integrity and authenticity; 2) vendor remote access; 3) information system planning; and 4) vendor risk management and procurement controls.[24] Furthermore, the draft Reliability Standard requires Responsible Entities to implement at least one process for verifying the integrity and authenticity of certain software and firmware and at least one process to control vendor remote access to high and medium impact BES Cyber Systems. For assets containing low impact BES Cyber Systems, the draft Reliability Standards states that Responsible Entities shall have and periodically review at least one cyber security policy that addresses integrity and authenticity of software and hardware and controls on vendor-initiated remote access. NERC must file this Reliability Standard with the Commission by September 2017. With the development of the draft Reliability Standard, NERC and industry are taking significant steps in addressing the risks posed by malware campaigns targeting supply chain vendors.

Through the NOI, the Commission is also specifically considering additional modifications aimed at mitigating the risks associated with the introduction of malware that could be introduced to BES Cyber Systems at Control Centers. Specifically, the Commission is evaluating the need to isolate BES Cyber Systems in Control Centers from the Internet and the potential need to use

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[24] Draft Reliability Standard CIP-013-1, Draft 1, *available at* http://www.nerc.com/pa/Stand/Project%20201603%20Cyber%20Security%20Supply%20Chain%20Managem/2016-03_CIP-013-1_draft_Jan_12_2017.pdf.

application whitelisting. As NERC discussed in its comments on the NOI, these controls could help protect BES Cyber Systems from threats such as malware. As NERC also pointed out in its comments, NERC and the Commission need to consider the operational impact of mandating such controls. Given the pending evaluation of these controls and the existing standard development work, it would be premature for the Commission to direct NERC to develop a malware standard, as requested by Resilient Societies.

Aside from the current standards development activity, NERC continuously assesses the efficacy of its Reliability Standards to help determine whether additional revisions are necessary. NERC considers information gathered from compliance monitoring and enforcement activities, known actual or potential threats to the BPS, and other input relevant to the Reliability Standards. At this time, NERC has determined that additional revisions to the CIP Reliability Standards, beyond those under consideration, are not necessary. Nevertheless, NERC will continue to assess the efficacy of the CIP Reliability Standards to help ensure the Reliability Standards include the appropriate protections.

C. NERC engages in other activities related to cyber security that help to reduce risks associated with malware.

NERC's approach to cyber security encompasses more than mandatory Reliability Standards. NERC use a number of security tools outside of the compliance context that have proved to be effective in enhancing the security of the BPS. For instance, through the E-ISAC, NERC has fostered an information sharing culture that promotes a proactive approach towards identification of malware, pooling of resources to combat malware, and sharing of best practices based on lessons learned, among other things.

"The E-ISAC, in collaboration with the DOE and the Electricity Subsector Coordinating Council, serves as the primary security communications channel for the Electricity Subsector and enhances the subsector's ability to prepare for and respond to cyber and physical threats, vulnerabilities, and incidents."[25] Members of the E-ISAC include vetted owners and operators of the BPS. Members receive private-level situational awareness on security threats, physical and cyber security bulletins, access to malware reverse engineering services, remediation, and other security resources. In addition, E-ISAC conducts outreach events to keep industry informed and prepared for cyber security threats. A key service offered by E-ISAC is malware identification and sharing this information with its members.

E-ISAC also leads security exercises every two years, known as GridEx, which simulate widespread, coordinated cyber and physical attacks on critical electric infrastructure. The last such exercise, GridEx III in November 2015, consisted of a two-day simulated security incident and an executive tabletop session featuring 32 industry executives and senior officials from federal and state governments.[26] More than 4,400 individuals from 364 organizations across North America participated in GridEx III, making it the largest geographically distributed grid security exercise to date.[27] GridEx IV is planned for November 2017. These events help strengthen entities' crisis response functions, which can be used to handle attacks from malware, and provide input for lessons learned.

Aside from E-ISAC activities, NERC also provides information sharing and learning opportunities that enhance industry practices in cyber security. NERC hosts the annual Grid Security Conference ("GridSecCon"). At GridSecCon, cyber security and physical security

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[25] *See* E-ISAC Vision, *available at* https://www.esisac.com/#about.

[26] *The Electricity Sector's Efforts to Respond to Cybersecurity Threats: Hearing before the Subcomm. On Energy of the H. Comm. On Energy and Commerce*, 115th Cong. 9-10 (2017) (statement of Gerry W. Cauley, President and Chief Executive Officer, North American Electric Reliability Corporation), *available at* http://docs.house.gov/meetings/IF/IF03/20170201/105497/HHRG-115-IF03-Wstate-CauleyG-20170201.pdf.

[27] *Id.* at 9.

experts from industry and government convene to share emerging security trends, policy advancements, and lessons learned related to the electricity sector.[28]

In addition, NERC communicates and works with industry to facilitate necessary information sharing. First, NERC issues NERC Alerts to provide security information to the electricity industry.[29] NERC Alerts can range from purely informational bulletins to identification of actions deemed essential to BPS reliability.[30] In 2016, NERC issued an alert related to the cyber security event in Ukraine. The alert focused on mitigating adversarial manipulation of industrial control systems based on lessons learned from the event. Second, NERC works with industry stakeholders on the Critical Infrastructure Protection Committee ("CIPC") to discuss relevant cyber and physical security matters and issue guidance documents to address cyber and physical security issues. For instance, in November 2015, a CIPC subcommittee developed guidelines for the electricity sector on control system electronic connectivity.[31] The guidelines identify industry recommendations on securing control system networks from threats, such as malware. Development of guidelines is an ongoing activity for CIPC that occurs in response to actual or potential threats or risks.

Finally, NERC and the Regional Entities provide continual outreach to industry to share best security practices. In November 2016, NERC hosted the Emerging Technology Roundtable on Substation Automation and International Electrotechnical Commission ("IEC") 61850 and

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28 *Id.* at 11.

29 NERC Alerts, *available at* http://www.nerc.com/pa/rrm/bpsa/Pages/Alerts.aspx.

30 *The Electricity Sector's Efforts to Respond to Cybersecurity Threats: Hearing before the Subcomm. On Energy of the H. Comm. On Energy and Commerce*, 115th Cong. 8 (2017) (statement of Gerry W. Cauley, President and Chief Executive Officer, North American Electric Reliability Corporation), *available at* http://docs.house.gov/meetings/IF/IF03/20170201/105497/HHRG-115-IF03-Wstate-CauleyG-20170201.pdf.

31 *Security Guidelines for the Electricity Sector: Control System Electronic Connectivity*, Critical Infrastructure Committee, Control Systems Security Working Group, Sep. 25, 2016, *available at* http://www.nerc.com/comm/CIPC/Control%20Systems%20Security%20Working%20Group%20CSSWG%202013/Control%20Systems%20Electronic%20Connectivity%20guideline.pdf.

Cloud Computing, which included discussion of the threat of malware to Control Centers.[32] Regional Entities also give workshops for entities within their regional footprints covering security topics. In addition, NERC and the Regional Entities hold webinars to increase industry awareness on security practices.

Through these activities, NERC promotes the necessary information sharing of cyber security threats and helps foster the type of incident reporting sought in the Petition.

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[32] *Session Recordings: Emerging Technology Roundtable – Substation Automation/IEC 61850* (Nov. 15, 2016), *available at* http://www.nerc.com/pa/CI/Documents/roundtable%20recording%20details%20-%20IEC%2061850%20%20(20161115).pdf; *Session Recordings: Emerging Technology Roundtable – Cloud Computing* (Nov. 16, 2016), *available at* http://www.nerc.com/pa/CI/Documents/roundtable%20recording%20details%20-%20cloud%20computing%20%20(20161116).pdf.

II. CONCLUSION

For the reasons stated above, NERC respectfully requests the Commission deny the Petition for rulemaking submitted by Resilient Societies. The currently enforceable CIP Reliability Standards include protections for BES Cyber Systems from the introduction of malware. In addition, NERC's current standards development activity is focusing on enhancements to the existing CIP Reliability Standards that will address, among other things, risks associated with malware. Finally, NERC and the E-ISAC work to facilitate information sharing among entities to identify and mitigate attacks from malicious actors and other threats to the security of the BPS. Nonetheless, NERC and the Commission will continue to review the CIP Reliability Standards for opportunities to increase their efficacy in protecting the BPS from the risk of malware and will consider modifications when appropriate. Therefore, the Commission does not need to direct further revisions to the CIP Reliability Standards at this time.

Respectfully submitted,

/s/ Marisa Hecht

Shamai Elstein
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Counsel for the North American Electric Reliability Corporation

Date: February 17, 2017

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service lists compiled by the Secretary in Docket No. AD17-9-000.

Dated at Washington, DC this 17th day of February, 2017.

/s/ Courtney M. Baughan
Courtney M. Baughan
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December 15, 2016

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: Informational Filing – Plan to Address Supply Chain Risk Management Directive
Docket No. RM15-14-002

Dear Secretary Bose:

Pursuant to footnote 85 of Order No. 829 ("Order"),[1] the North American Electric Reliability Corporation ("NERC") hereby submits an informational filing outlining its plan to address the Federal Energy Regulatory Commission's ("Commission") directive from the Order. In Order No. 829, the Commission directed NERC to submit a new or modified Reliability Standard addressing supply chain risk management for industrial control system hardware, software, and computing and networking services associated with bulk electric system operations within one year of the effective date of the Order, which is September 27, 2017. The attached project plan sets forth NERC's activities and anticipated milestones for meeting the September 27, 2017 deadline.

Should you have any questions, please do not hesitate to contact the undersigned.

Respectfully submitted,

/s/ Shamai Elstein
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Counsel to the North American Electric Reliability Corporation

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[1] Order No. 829, *Revised Critical Infrastructure Protection Reliability Standards*, 156 FERC ¶ 61, 050, 81 Fed. Reg. 49878 (2016).

Project Plan - Project 2016-03 Cyber Security Supply Chain Management

Action	Actual/Estimated Completion Date
Nomination period for Standard Authorization Request (SAR) and standard drafting team (SDT)	7/29/16 – 8/18/16
Standards Committee appointed SDT	9/14/16
In-Person SDT Meeting	10/17/16 – 10/19/16
Standard Committee approval of SAR	10/19/16
Informal comment period on SAR	10/20/16 – 11/18/16
Technical Conference	11/10/16
In-Person SDT Meeting	11/29/16 – 12/1/16
Standard Committee approval of revised SAR	12/14/16
Standard Committee approval of posting new and/or modified Reliability Standard(s) to address Order No. 829 directive for 45-day comment period and ballot	1/18/17
Initial comment period and ballot on new and/or modified Reliability Standard(s)	1/19/17 – 3/6/17
In-Person SDT Meeting	March 2017
Additional comment period and ballot on new and/or modified Reliability Standard(s), if necessary	4/12/17 – 5/26/17
In-Person SDT Meeting	Early June 2017
Final Ballot on new and/or modified Reliability Standard(s)	June 2017
NERC Board of Trustees adoption of new and/or modified Reliability Standard(s)	August 2017
Submit petition for approval of new and/or modified Reliability Standard(s) to Federal Energy Regulatory Commission	September 2017

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD17-3-000

January 24, 2017

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005

Attention: Lauren Perotti
Counsel for North American Electric Reliability Corporation

Reference: Interpretation of Regional Reliability Standard BAL-002-WECC-2a

Dear Ms. Perotti:

On November 9, 2016, the North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) filed a joint petition seeking approval of an interpretation of regional Reliability Standard BAL-002-WECC-2a. The proposed interpretation provides clarification regarding the types of resources that may be used to satisfy Contingency Reserve requirements in regional Reliability Standard BAL-002-WECC-2.

NERC states that the proposed interpretation incorporates into the standard document the Commission's determination, in Order No. 789, approving regional Reliability Standard BAL-002-WECC-2, that non-traditional resources may qualify as "Operating Reserve – Spinning" provided those resources satisfy the technical and performance requirements in Requirement R2.[1]

NERC's and WECC's joint filing was noticed on December 6, 2016, with interventions, comments and protests due on or before January 05, 2017. No comments or protests were received.

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[1] *Regional Reliability Standard BAL-002-WECC-2 – Contingency Reserve*, Order No. 789, 145 FERC ¶ 61,141, P 48 (2013).

NERC's uncontested petition is hereby approved pursuant to the relevant authority delegated to the Director, Office of Electric Reliability under 18 C.F.R. § 375.303 (2016), 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 (2016).

Sincerely,

Michael Bardee, Director
Office of Electric Reliability

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD17-1-000

January 18, 2017

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005

Attention: Candice Castaneda
Counsel for North American Electric Reliability Corporation

Reference: Petition of the North American Electric Reliability Corporation for Approval of retirement of currently-effective Reliability Standard BAL-004-0

Dear Ms. Castaneda:

On November 10, 2016, the North American Electric Reliability Corporation (NERC) filed a petition for Commission approval of retirement, pursuant to section 215(d)(1) of the Federal Power Act (FPA)[1] and Section 39.5 of the Commission's regulations,[2] of currently-effective Reliability Standard BAL-004-0 (Time Error Correction). NERC also seeks approval to retire Reliability Standard BAL-004-0 effective on the later of: (i) the first day of the first calendar quarter after the effective date of the Commission's order approving retirement; or (ii) the effective date of retirement/reservation[3] of North American Energy Standard Board ("NAESB") WEQ-006 Manual Time Error Correction Business Practice Standard ("NAESB WEQ-006"). NERC's proposal is conditioned upon retirement of NAESB WEQ-006 to avoid uncoordinated manual Time Error Correction. NERC understands that NAESB's effort

[1] 16 U.S.C. § 824o (2012).

[2] 18 C.F.R. § 39.5 (2016).

[3] The NAESB process uses the term reservation, in lieu of retirement.

regarding proposed retirement of NAESB WEQ-006 is underway and NAESB will make an informational filing following the completion of its standards development process.

The purpose of Reliability Standard BAL-004-0 is to ensure that Time Error Correction is conducted in a manner that does not adversely affect the reliability of the Interconnection. Reliability Standard BAL-004-0 establishes a process to invoke a Time Error Correction, if necessary, that would be overseen by reliability coordinators and implemented by balancing authorities.[4] NERC states that manual Time Error Correction places the Interconnection closer to the appropriate frequency through an offset to the frequency schedule as requested by an Interconnection Time Monitor (one of many roles of the reliability coordinator).[5] NERC explains that since Reliability Standard BAL-004-0 became effective, improvements have been made to mandatory Reliability Standards (such as the development of Reliability Standards BAL-003-1.1 and BAL-001-2 and the Interconnection Reliability Operations and Coordination (IRO) Standards) that help ensure continued adherence to frequency approximating 60 Hertz over long-term averages and make Reliability Standard BAL-004-0 redundant.

As part of the support for the retirement of Reliability Standard BAL-004-0, the NERC Operating Committee approved *Manual Time Error Correction Reference Document*[6] which is "intended to help ease the transition upon retirement of BAL-004-0 and assure the Commission and potential non-utility industry that if [Time Error Correction] is determined necessary, it will be performed in a coordinated and reliable manner."[7]

NERC's filing was noticed on November 18, 2016, with interventions, comments and protests due on or before December 19, 2016. No interventions, comments or protests were received.

NERC's uncontested petition is hereby approved pursuant to the relevant authority delegated to the Director, Office of Electric Reliability under 18 C.F.R. § 375.303 (2016), effective as set forth in NERC's implementation plan.

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[4] The NERC Glossary of Terms defines Time Error Correction as, "An offset to the Interconnection's scheduled frequency to return the Interconnection's Time Error to a predetermined value."

[5] NERC Petition at 3.

[6] NERC Petition, Exhibit C-3 (Manual Time Error Correction Reference Document).

[7] NERC Petition at 18.

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 (2016).

Sincerely,

Michael Bardee, Director
Office of Electric Reliability

Document Content(s)

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD17-2-000

December 27, 2016

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005

Attention: Shamai Elstein
Senior Counsel for North American Electric Reliability Corporation

Reference: Interpretation of Reliability Standard CIP-002-5.1a — Cyber Security — BES Cyber System Categorization

Dear Mr. Elstein:

On November 28, 2016, the North American Electric Reliability Corporation (NERC) submitted a filing seeking Commission approval of an interpretation of Reliability Standard CIP-002-5.1a — Cyber Security — BES Cyber System Categorization. NERC requests that the proposed interpretation become effective upon Commission approval. [1]

The purpose of Reliability Standard CIP-002-5.1 is to identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the bulk electric system.[2] The criteria used to categorize BES Cyber Systems are set forth in Attachment 1 to Reliability Standard CIP-002-5.1.

[1] Consistent with NERC numbering convention, upon approval of the proposed interpretation, the standard number would be CIP-002-5.1a.

[2] *See* Reliability Standard CIP-002-5.1 (Cyber Security – BES Cyber System Categorization), at 1.

NERC states that the proposed interpretation provides clarification regarding the meaning of the phrase "shared BES Cyber Systems" in Criterion 2.1 of Attachment 1 to Reliability Standard CIP-002-5.1. Specifically, NERC states that the proposed interpretation "provides that: (1) the phrase 'shared BES Cyber Systems' in Criterion 2.1 refers to discrete BES Cyber Systems that are shared by multiple generation units; and (2) the evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System."[3]

NERC's petition was noticed on November 29, 2016, with interventions, comments and protests due on or before December 20, 2016. No interventions, comments or protests were received.

NERC's uncontested petition is hereby approved pursuant to the relevant authority delegated to the Director, Office of Electric Reliability, under 18 C.F.R. § 375.303 (2016), effective as of the date of this order.

This action shall not be construed as accepting 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 which have been or which 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 (2016).

Sincerely,

Michael Bardee, Director
Office of Electric Reliability

[3] *See* NERC Petition at 1.

Document Content(s)

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD16-6-001

December 14, 2016

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005

Attention: Lauren A. Perotti
Counsel for North American Electric Reliability Corporation

Reference: Revisions to the Violation Risk Factors for Reliability Standards IRO-018-1 and TOP-010-1, Docket No. RD16-6-001.

Dear Ms. Perotti:

On September 22, 2016, in Docket No. RD16-6-000,[1] the Commission approved Reliability Standards IRO-018-1 (Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities) and TOP-010-1 (Real-time Reliability Monitoring and Analysis Capabilities) and associated implementation plan, Violation Severity Levels, and several of the proposed Violation Risk Factors (VRF). The Commission also directed NERC to submit a compliance filing within 60 days of issuance of the September 22 Order revising the VRF designations for Requirement R1 in Reliability Standard IRO-018-1 and Requirements R1 and R2 in Reliability Standard TOP-010-1 from "medium" to "high".

On November 2, 2016, NERC filed for Commission approval the revised VRF designations, consistent with the Commission's directive in the September 22 Order.

NERC's filing was noticed on November 7, 2016, with interventions, comments and protests due on or before December 7, 2016. No interventions, comments or protests were received.

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[1] *North American Electric Reliability Corp.*, 156 FERC ¶ 61,207 (2016) ("September 22 Order").

NERC's uncontested petition is hereby approved pursuant to the relevant authority delegated to the Director, Office of Electric Reliability under 18 C.F.R. § 375.303 (2016), 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 (2016).

Sincerely,

Michael Bardee, Director
Office of Electric Reliability

158 FERC ¶ 61,042
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM16-20-000]

Remedial Action Schemes Reliability Standard

(January 19, 2017)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission proposes to approve Reliability Standard PRC-012-2 (Remedial Action Schemes) submitted by the North American Electric Reliability Corporation. The purpose of proposed Reliability Standard PRC-012-2 is to ensure that remedial action schemes do not introduce unintentional or unacceptable reliability risks to the bulk electric system.

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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Division of Reliability Standards and Security
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Alan Rukin (Legal Information)
Office of the General Counsel
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
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SUPPLEMENTARY INFORMATION:

158 FERC ¶ 61,042
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Remedial Action Schemes Reliability Standard Docket No. RM16-20-000

NOTICE OF PROPOSED RULEMAKING

(January 19, 2017)

1. Pursuant to section 215 of the Federal Power Act (FPA), the Commission proposes to approve proposed Reliability Standard PRC-012-2 (Remedial Action Schemes). The North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), submitted proposed Reliability Standard PRC-012-2 for approval. The purpose of proposed Reliability Standard PRC 012-2 is to ensure that remedial action schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the bulk electric system. In addition, the Commission proposes to approve the associated violation risk factors and violation severity levels, implementation plan, and effective date proposed by NERC. NERC also submitted proposals to retire two currently-effective Reliability Standards and to withdraw three Reliability Standards that are pending review before the Commission. While proposing to approve Reliability Standard PRC-012-2, the Commission seeks clarifying comments addressing "limited impact" RAS. Based on comments and information received, the Commission may issue directives as appropriate.

I. Background

A. Section 215 and Mandatory Reliability Standards

2. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval.[1] Once approved, the Reliability Standards may be enforced by the ERO subject to Commission oversight, or by the Commission independently.[2] In 2006, the Commission certified NERC as the ERO pursuant to section 215 of the FPA.[3]

B. Order No. 693

3. On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 Reliability Standards filed by NERC, including Reliability Standards PRC-015-1 (Remedial Action Scheme Data and Documentation) and PRC-016-1 (Remedial Action Scheme Misoperation).[4] Reliability Standard PRC-015-1 requires transmission owners, generator owners, and distribution providers to maintain a listing; retain evidence of review; and provide documentation of existing, new or functionally modified special

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[1] 16 U.S.C. 824o(c), (d) (2012).

[2] *Id.* 824o(e).

[3] *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), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[4] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. and Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

protection systems.[5] Reliability Standard PRC-016-1 requires transmission owners, generator owners, and distribution providers to provide the regional reliability organization with documentation, analyses and corrective action plans for misoperation of special protection systems.[6]

4. In Order No. 693, the Commission determined that proposed Reliability Standard PRC-012-0 was a "fill-in-the-blank" Reliability Standard because, while it was proposed to require regional reliability organizations to ensure that all special protection systems are properly designed, meet performance requirements, and are coordinated with other protection systems, NERC had not submitted any regional review procedures with this standard.[7] The Commission also determined that proposed Reliability Standard PRC-013-0 was a "fill-in-the-blank" Reliability Standard because, although it was proposed to ensure that all special protection systems are properly designed, meet performance requirements, and are coordinated with other protection systems by requiring the regional reliability organization to maintain a database of information on special protection systems, NERC had not filed any regional procedures for maintaining

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[5] *Id.* PP 1529-1533.

[6] *Id.* PP 1534-1540.

[7] *Id.* PP 1517-18, 1520. The Commission used the term "fill-in-the-blank" standards to refer to proposed Reliability Standards that required the regional reliability organizations to develop at a later date criteria for use by users, owners or operators within each region. *Id.* P 297.

the databases.[8] Further, the Commission determined that proposed Reliability Standard PRC-014-0 was a "fill-in-the-blank" Reliability Standard because, while it was proposed to ensure that special protection systems are properly designed, meet performance requirements, and are coordinated with other protection systems by requiring the regional reliability organization to assess and document the operation, coordination, and compliance with NERC Reliability Standards and effectiveness of special protection systems at least once every five years, NERC had not submitted any regional procedures for this assessment and documentation.[9] The Commission stated that it would not approve or remand proposed Reliability Standards PRC-012-0, PRC-013-0 or PRC-014-0 until NERC submitted the additional necessary information to the Commission.[10]

C. Remedial Acton Schemes

5. On June 23, 2016, the Commission approved NERC's revision to NERC Glossary of Terms that redefines special protection system to have the same definition as RAS, effective April 1, 2017.[11] Effective April 1, 2017, the NERC Glossary of Terms will define Remedial Action Scheme to mean:

> A scheme designed to detect predetermined System

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[8] *Id.* PP 1521, 1522, 1524.

[9] *Id.* PP 1525, 1526, 1528.

[10] *Id.* PP 1520, 1524, 1528.

[11] *N. Am. Elec. Reliability Corp.*, Docket No. RD16-5-000 (June 23, 2016) (delegated letter order); NERC Glossary of Terms, http://www.nerc.com/files/glossary_of_terms.pdf.

> conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as:
>
> - Meet requirements identified in the NERC Reliability Standards;
> - Maintain Bulk Electric System (BES) stability;
> - Maintain acceptable BES voltages;
> - Maintain acceptable BES power flows;
> - Limit the impact of Cascading or extreme events.[12]

The revised RAS definition also identifies fourteen items that do not individually constitute a RAS.

D. NERC Petition and Proposed Reliability Standard PRC-012-2

6. On August 5, 2016, NERC submitted a petition seeking Commission approval of proposed Reliability Standard PRC-012-2.[13] NERC contends that proposed Reliability Standard PRC-012-2 is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[14] NERC explains that the intent of proposed Reliability Standard PRC-012-2 is to supersede "pending" Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1 and to retire and replace currently-effective Reliability Standards PRC-015-1

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[12] NERC Glossary of Terms, http://www.nerc.com/files/glossary_of_terms.pdf; *see also Revisions to Emergency Operations Reliability Standards; Revisions to Undervoltage Load Shedding Reliability Standards; Revisions to the Definition of "Remedial Action Scheme" and Related Reliability Standards*, Order No. 818, 153 FERC ¶ 61,228, at PP 24, 31 (2015).

[13] Proposed Reliability Standard PRC-012-2 is not attached to this Notice of Proposed Rulemaking. The proposed Reliability Standard is available on the Commission's eLibrary document retrieval system in Docket No. RM16-20-000 and is posted on NERC's website, http:// www.nerc.com.

[14] NERC Petition at 2.

and PRC-016-1.[15] NERC states that proposed Reliability Standard PRC-012-2 represents substantial improvements over these Reliability Standards because it streamlines and consolidates existing requirements; corrects the applicability of previously unapproved Reliability Standards; and implements a continent-wide RAS review program.[16]

7. NERC states that, in the United States, proposed Reliability Standard PRC-012-2 will apply to reliability coordinators, planning coordinators, and RAS-entities. Proposed Reliability Standard PRC-012-2 defines RAS-entities to include the transmission owner, generation owner, or distribution provider that owns all or part of a RAS.

8. NERC states that proposed Reliability Standard PRC-012-2 includes nine requirements that combine all existing (both effective and "pending") Reliability Standards into a single, consolidated, continent-wide Reliability Standard to address all aspects of RAS.[17] NERC states that all of the requirements in Reliability Standard PRC-012-1 except R2 are now covered in Requirements R1, R2, R3, R4, R5, R6, and R8 of proposed Reliability Standard PRC-012-2.[18] NERC explains that Reliability Standard PRC-012-1, Requirement R2 is "administrative in nature and does not contribute to

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[15] NERC notes that it submitted "for completeness" revised versions of Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1 in its petition to revise the definition of RAS, but NERC did not request Commission approval of the revised Reliability Standards in that proceeding. *Id.* at 1 n.5.

[16] *Id.* at 12-13.

[17] *Id.* at 3.

[18] *Id.* at 40.

reliability."[19] NERC also states that it established Requirement R9 of proposed Reliability Standard PRC-012-2 to replace the mandate in Reliability Standard PRC-013-1 that responsible entities maintain a RAS database with pertinent technical information for each RAS.[20] NERC explains that proposed Reliability Standard PRC-012-2 Requirements R4 and R6 cover the review and the mandate to take corrective action required by Reliability Standard PRC-014-1.[21] NERC states that it integrated the performance requirements in Reliability Standard PRC-015-1 into proposed Reliability Standard PRC-012-2 Requirements R1, R2, and R3.[22] NERC maintains that it integrated the performance requirements in Reliability Standard PRC-016-1 into proposed Reliability Standard PRC-012-2 Requirements R5, R6, and R7.[23]

9. NERC explains how the nine Requirements in proposed Reliability Standard PRC-012-2 work together and with other Reliability Standards. Proposed Requirements R1, R2, and R3, together, establish a process for the reliability coordinator to review new or modified RAS schemes.[24] The reliability coordinator must complete the review before an entity places a new or functionally modified RAS into service.

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[19] *Id.* at 41.

[20] *Id.* at 42.

[21] *Id.* at 43.

[22] *Id.* at 43-44.

[23] *Id.* at 44-45.

[24] *Id.* at 15-18.

10. Proposed Requirement R4 requires the planning coordinator to perform a periodic evaluation of each RAS within its planning area, at least once every five years.[25] The evaluation must determine, *inter alia*, whether each RAS: (1) mitigates the system conditions or contingencies for which it was designed; and (2) avoids adverse interactions with other RAS and protection systems. Proposed Requirement R4, Part 4.1.3 footnote 1 defines a certain subset of RAS as "limited impact" RAS to mean "A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations."[26] Further, proposed Requirement R4, Parts 4.1.3, 4.1.4, and 4.1.5 provide certain exceptions to "limited impact" RAS. For example, Part 4.1.5 states that:

> Except for limited impact RAS, a single component failure in the RAS, when the RAS is intended to operate does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed.[27]

NERC explains that proposed Requirement R4 "does not supersede or modify [planning coordinator] responsibilities under Reliability Standard TPL-001-4."[28] NERC continues

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[25] *Id.* at 18-22.

[26] *Id.* at 19 & n.44.

[27] *Id.* at 19.

[28] *Id.* at 28.

that even though Part 4.1.5 exempts “limited impact” RAS from certain aspects of proposed Requirement R4, proposed Reliability Standard PRC-012-2 does not exempt “limited impact” RAS from meeting each of the performance requirements in Reliability Standard TPL-001-4.[29]

11. NERC states that prior to development of proposed Reliability Standard PRC-012-2, two NERC Regions, the Northeast Power Coordinating Council (NPCC) and the Western Electric Coordinating Council (WECC), used individual RAS classification regimes to identify RAS that would meet criteria similar to those for RAS described as “limited impact” in proposed Reliability Standard PRC-012-2.[30] NERC continues that the standard drafting team identified the Local Area Protection Scheme (LAPS) classification in WECC and the Type III classification in NPCC as consistent with the “limited impact” designation.[31] According to NERC, RAS implemented prior to the effective date of proposed Reliability Standard PRC-012-2 that have gone through the regional review processes of WECC or NPCC and that are classified as either a LAPS by WECC or a Type III by NPCC, would be considered a “limited impact” RAS for purposes of proposed Reliability Standard PRC-012-2.[32]

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[29] *Id.* at 28-29.

[30] *Id.* at 25.

[31] *Id.* at 25-26.

[32] *Id.* at 26.

12. Proposed Requirements R5, R6, and R7 pertain to the analysis of each RAS operation or misoperation.[33] The RAS-entity must perform an analysis of each RAS operation or misoperation and provide the results to the reviewing reliability coordinator. Further, the RAS-entity must develop and submit a corrective action plan to the reviewing reliability coordinator after learning of a deficiency with its RAS, implement the corrective action plan, and update it as necessary. Proposed Requirement R8 requires periodic testing of RAS performance: every six years for normal RAS and 12 years for "limited impact" RAS.[34] Proposed Requirement R9 requires the reliability coordinator to annually update its RAS database.[35]

13. NERC proposes an implementation plan that includes an effective date for proposed Reliability Standard PRC-012-2 that is the first day of the first calendar quarter that is thirty-six months after the date that the Commission approves the proposed Reliability Standard. Concurrent with the effective date, the implementation plan calls for the retirement of currently-effective Reliability Standards PRC-015-1 and PRC-016-1 and withdrawal of "pending" Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1.

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[33] *Id.* at 29-34.

[34] *Id.* at 34-36.

[35] *Id.* at 36-38.

II. Discussion

14. Pursuant to section 215(d)(2) of the FPA, we propose to approve proposed Reliability Standard PRC-012-2 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. We also propose to approve the associated violation risk factors and violation severity levels, implementation plan, and effective date proposed by NERC. Further, we propose to approve the withdrawal of "pending" Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1 and retirement of currently-effective Reliability Standards PRC-015-1 and PRC-016-1, as proposed by NERC.

15. Proposed Reliability Standard PRC-012-2 enhances reliability by addressing all aspects of RAS in a single, continent-wide Reliability Standard and by assigning specific RAS responsibilities to appropriate functional entities. Accordingly, proposed Reliability Standard PRC-012-2 satisfies the relevant directive in Order No. 693. In addition, we agree with NERC that Reliability Standards PRC-015-1 and PRC-016-1 can be retired as proposed in the implementation plan due to their consolidation with proposed Reliability Standard PRC-012-2.

16. NERC's petition states that proposed Reliability Standard PRC-012-2 does not exempt "limited impact" RAS from meeting all system performance requirements of Reliability Standard TPL-001-4. We propose to clarify that, consistent with NERC's explanation, proposed Reliability Standard PRC-012-2 will not modify or supersede any

system performance obligations under Reliability Standard TPL-001-4.[36] For example, under Reliability Standard TPL-001-4, Table 1 non-consequential load loss may not exceed 75 MW for certain Category P1, P2, or P3 contingencies following the Reliability Standard TPL-001-4 stakeholder process.[37] We seek comment on this proposal.

17. We also seek comment on the processes used to ensure the LAPS or Type III RAS will be compliant with Reliability Standard TPL-001-4 prior to the effective date of Reliability Standard PRC-012-2, including a description of considerations on whether the load disconnected by each RAS installation is consequential or non-consequential, and if non-consequential load loss is greater than 75 MW.[38] We further seek comment on whether the term "limited impact RAS" should be defined in the Glossary of Terms Used in NERC Reliability Standards.

III. Information Collection Statement

18. The collection of information addressed in this Notice of Proposed Rulemaking is subject to review by the Office of Management and Budget (OMB) under section 3507(d)

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[36] *See* NERC Petition at 28 ("Requirement R4 of PRC-012-2 does not supersede or modify [planning coordinator] responsibilities under Reliability Standard TPL-001-4…").

[37] Reliability Standard TPL-001-4, Table 1 (Steady State & Stability Performance Extreme Events), footnote 12 and Attachment 1.

[38] The Commission notes that WECC's and NPCC's RAS criteria and associated regional terms found in the "Technical Justification" section of proposed Reliability Standard PRC-012-2 were not submitted for approval by NERC and as such are not part of this proceeding.

of the Paperwork Reduction Act of 1995.[39] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[40] 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. The Commission will submit the information collection requirement to OMB for its final review and approval. The Commission solicits public comments on the 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.

20. The information collection requirements in this Notice of Proposed Rulemaking in Docket No. RM16-20-000 is associated with FERC-725A (OMB Control No. 1902-0244) and FERC-725G (OMB Control No. 1902-0252).

21. Public Reporting Burden: The Commission proposes to approve Reliability Standard PRC-012-2. The proposed Reliability Standard PRC-012-2 consolidates so-called "fill-in-the-blank" Reliability Standards PRC-012-1, PRC-013-1 and PRC-014-1, as well as, Commission-approved Reliability Standards PRC-015-1 and PRC-016-1, into

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[39] 44 U.S.C. 3507(d) (2012).

[40] 5 CFR 1320.11 (2016).

one standard. The proposed Reliability Standard PRC-012-2 improves upon the existing standards because it removes ambiguity in NERC's original "fill-in-the-blank" Reliability Standards by assigning responsibility to appropriate functional entities. It also streamlines and consolidates the RAS Reliability Standards into one clear, effective Reliability Standard. The number of respondents below is based on an examination of the NERC compliance registry for reliability coordinators, planning coordinators, transmission owners, generation owners, and distribution providers and an estimation of how many entities from that registry will be affected by the proposed Reliability Standard. At the time of Commission review of proposed Reliability Standard PRC-012-2, 15 reliability coordinators, 71 planning coordinators, 328 transmission owners, 930 generation owners, and 367 distribution providers in the United States were registered in the NERC compliance registry. However, under NERC's compliance registration program, entities may be registered for multiple functions, so these numbers incorporate some double counting. The Commission notes that many generation sites share a common generation owner. The following table illustrates the estimated burden to be applied to the information collection.[41]

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[41] In the burden table, engineering is abbreviated as "Eng." and record keeping is abbreviated as "R.K."

RM16-20-000 (Mandatory Reliability Standards: Reliability Standard PRC-012-2)					
Requirement and Respondent Category for PRC-012-2	**Number of Respondents (1)**	**Number of Responses per Respondent (2)**	**Total Number of Responses (1)*(2)=(3)**	**Average Burden Hours & Cost per Response[42] (4)**	**Annual Burden Hours & Total Annual Cost (3)*(4)=(5)**
R1. Each RAS-entity (TO, GO, DP)	1,595	1	1,595	(Eng.) 24 hrs. ($1,543); (R.K.) 12 hrs. ($453)	57,420 hrs. (38,280 Eng., 19,140 R.K.); $3,183,556 ($2,461,021 Eng., $722,535 R.K.)
R2. Each Reliability Coordinator	15	1	15	(Eng.) 16 hrs. ($1,029); (R.K.) 4 hrs. ($151)	300 hrs. (240 Eng., 60 R.K.); $17,695 ($15,430 Eng., $2,265 R.K.)
R4. Each Planning Coordinator	71	1	71	(Eng.) 16 hrs. ($1,029); (R.K.) 4 hrs. ($151)	1,420 hrs. (1,136 Eng., 284 R.K.); $85,754 ($73,033 Eng., $10,721 R.K.)
R5, R6, R7, and R8. Each RAS-entity (TO, GO, DP)	1,595	1	1,595	(Eng.) 24 hrs. ($1,543); (R.K.) 12 hrs. ($453)	57,420 hrs. (38,280 Eng., 19,140 R.K.); $3,183,556 ($2,461,021 Eng., $722,535 R.K.)
R9. Each Reliability Coordinator	15	1	15	(Eng.) 10 hrs. ($653); (R.K.) 4 hrs. ($151)	210 hrs. (150 Eng., 60 R.K.); $11,909 ($9,644 Eng., $2,265 R.K.)
TOTAL			**3,291**		**116,770 hrs. (78,086 Eng., 38,684 R.K.); $6,480,470 ($5,020,149 Eng.; $1,460,321 R.K.)**

Title: FERC-725A (Mandatory Reliability Standards); FERC-725G (Mandatory Reliability Standards: PRC-012-2)

Action: Revision to existing collections.

OMB Control No: 1902-0244 (FERC-725A); 1902-0252 (FERC-725G)

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[42] The estimates for cost per response are derived using the following formula: Burden Hours per Response * $/hour = Cost per Response. The $64.29/hour figure for an engineer and the $37.75/hour figure for a record clerk are based on the average salary plus benefits data from the Bureau of Labor Statistics.

Respondents: Business or other for profit, and not for profit institutions.

Frequency of Responses: Annually

Necessity of the Information: Proposed Reliability Standard PRC-012-2 sets forth Requirements for remedial action schemes to ensure that remedial action schemes do not introduce unintentional or unacceptable reliability risks to the bulk electric system and are coordinated to provide the service to the system as intended.

Internal review: 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.

22. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, Office of the Executive Director, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, e-mail: DataClearance@ferc.gov, phone: (202) 502-8663, fax: (202) 273-0873].

23. Comments concerning the information collection proposed in this Notice of Proposed Rulemaking 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 FERC-725A and FERC-725G and the docket number of this Notice of Proposed Rulemaking (Docket No. RM16-20-000) in your submission.

IV. Environmental Analysis

24. 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.[43] The action proposed here falls within the categorical exclusion in the Commission's regulations for rules that are clarifying, corrective or procedural, for information gathering, analysis, and dissemination.[44]

V. Regulatory Flexibility Act

25. The Regulatory Flexibility Act of 1980 (RFA)[45] generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities.

26. The proposed Reliability Standard PRC-012-2 will apply to approximately 1681 entities in the United States. Comparison of the applicable entities with the Commission's small business data indicates that approximately 1,025 are small entities or 61 percent of the respondents affected by proposed Reliability Standard PRC-012-2.[46]

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[43] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Preambles 1986-1990 ¶ 30,783 (1987).

[44] 18 CFR 380.4(a)(2)(ii) (2016).

[45] 5 U.S.C. 601-612 (2012).

[46] 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 Notice of Proposed Rulemaking, we apply a 500 employee threshold for each affected entity. Each entity is *(continued ...)*

The Commission estimates for these small entities, proposed Reliability Standard PRC-012-2 may need to be evaluated and documented every five years with a cost of $6,322 for each evaluation. The Commission views this as a minimal economic impact for each entity. Accordingly, the Commission certifies that the proposed Reliability Standard PRC-012-2 will not have a significant economic impact on a substantial number of small entities.

VI. Comment Procedures

27. 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. RM16-20-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

28. 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.

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classified as Electric Bulk Power Transmission and Control (NAICS code 221121).

29. 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.

30. 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 below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VII. Document Availability

31. 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.

32. 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.

33. 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.

158 FERC ¶ 61,041
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, and Colette D. Honorable.

Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events — Docket No. RM15-11-001

ORDER NO. 830-A

ORDER DENYING REHEARING

(Issued January 19, 2017)

1. In Order No. 830, the Commission approved Reliability Standard TPL-007-1 (Transmission System Planned Performance for Geomagnetic Disturbance Events) submitted by the North American Electric Reliability Corporation (NERC).[1] In addition, the Commission directed NERC to develop certain modifications to Reliability Standard TPL-007-1 and submit a work plan and, subsequently, one or more informational filings that address specific geomagnetic disturbance (GMD)-related research areas. Foundation for Resilient Societies (Resilient Societies), Edison Electric Institute (EEI), Center for Security Policy (CSP) and Jewish Institute for National Security Affairs (JINSA) filed requests for rehearing of Order No. 830. For the reasons discussed in the body of this order, we deny rehearing.

I. **Background**

A. **Order No. 779**

2. In Order No. 779, the Commission directed NERC, pursuant to section 215(d)(5) of the Federal Power Act (FPA),[2] to develop and submit for approval proposed Reliability Standards that address the impact of GMDs on the reliable operation of the

[1] *Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, Order No. 830, 81 Fed. Reg. 67,120 (Sept. 30, 2016), 156 FERC ¶ 61,215 (2016).

[2] 16 U.S.C. § 824o(d)(5) (2012).

Bulk-Power System.[3] The Commission determined that the potentially severe, wide-spread impact on the reliable operation of the Bulk-Power System that can be caused by GMD events, and the then absence of Reliability Standards to address GMD events, justified the development of Reliability Standards.

3. The Commission ordered NERC to implement the Commission's directive in two stages. In the first stage, the Commission directed NERC to submit, within six months of the effective date of Order No. 779, one or more Reliability Standards (First Stage GMD Reliability Standards) that require owners and operators of the Bulk-Power System to develop and implement operational procedures to mitigate the effects of GMDs consistent with the reliable operation of the Bulk-Power System.[4] The Commission directed that NERC, in the Second Stage GMD Reliability Standards, provide more comprehensive protections by requiring applicable entities to protect their facilities against a "benchmark GMD event."

B. <u>NERC Petition</u>

4. On January 21, 2015, NERC petitioned the Commission to approve Reliability Standard TPL-007-1 and its associated violation risk factors and violation severity levels, implementation plan, and effective dates. NERC also proposed a definition for the term "Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment" for inclusion in the NERC Glossary of Terms. NERC maintained that Reliability Standard TPL-007-1 is just, reasonable, not unduly discriminatory or preferential and in the public interest. NERC also asserted that Reliability Standard TPL-007-1 satisfied the directive in Order No. 779 corresponding to the Second Stage GMD Reliability Standards.

C. <u>Order No. 830</u>

5. In Order No. 830, the Commission approved Reliability Standard TPL-007-1. The Commission determined that Reliability Standard TPL-007-1 addressed the directives in Order No. 779 corresponding to the development of the Second Stage GMD Reliability Standards. Order No. 830 explained that Reliability Standard TPL-007-1 addressed the

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[3] *Reliability Standards for Geomagnetic Disturbances*, Order No. 779, 78 Fed. Reg. 30,747 (May 23, 2013), 143 FERC ¶ 61,147, *reh'g denied*, 144 FERC ¶ 61,113 (2013).

[4] The Commission approved the First Stage GMD Reliability Standard, EOP-010-1, in Order No. 797. *Reliability Standard for Geomagnetic Disturbance Operations*, Order No. 797, 79 Fed. Reg. 35,911 (June 25, 2014), 147 FERC ¶ 61,209, *reh'g denied*, Order No. 797-A, 149 FERC ¶ 61,027 (2014).

Commission's directives by requiring applicable Bulk-Power System owners and operators to conduct, on a recurring five-year cycle, initial and ongoing vulnerability assessments regarding the potential impact of a benchmark GMD event on the Bulk-Power System as a whole and on Bulk-Power System components. In addition, the Commission determined that Reliability Standard TPL-007-1 requires applicable entities to develop and implement corrective action plans to mitigate vulnerabilities identified through those recurring vulnerability assessments and that potential mitigation strategies identified in Reliability Standard TPL-007-1 include, but are not limited to, the installation, modification or removal of transmission and generation facilities and associated equipment. Order No. 830 concluded that Reliability Standard TPL-007-1 constitutes an important step in addressing the risks posed by GMD events to the Bulk-Power System.

6. In addition to approving Reliability Standard TPL-007-1, in Order No. 830, the Commission determined that Reliability Standard TPL-007-1 should be modified to reflect new information and analyses. Specifically, Order No. 830 directed NERC to develop and submit modifications to Reliability Standard TPL-007-1 concerning: (1) the calculation of the reference peak geoelectric field amplitude component of the benchmark GMD event definition; (2) the collection and public availability of necessary geomagnetically-induced current (GIC) monitoring and magnetometer data; and (3) deadlines for completing corrective action plans and the mitigation measures called for in corrective action plans. Order No. 830 directed NERC to develop and submit these revisions for Commission approval within 18 months of the effective date of Order No. 830.

7. Further, to improve the understanding of GMD events, in Order No. 830, the Commission directed NERC to submit within six months from the effective date of Order No. 830 a GMD research work plan. Regarding the work plan, Order No. 830 directed NERC to: (1) further analyze the area over which spatial averaging should be calculated for stability studies, including performing sensitivity analyses on squares less than 500 km per side (e.g., 100 km, 200 km); (2) further analyze earth conductivity models by, for example, using metered GIC and magnetometer readings to calculate earth conductivity and using 3-D readings; (3) determine whether new analyses and observations support modifying the use of single station readings around the earth to adjust the spatially averaged benchmark for latitude; (4) research aspects of the required thermal impact assessments; and (5) in NERC's discretion, conduct any GMD-related research areas generally that may impact the development of new or modified GMD Reliability Standards.

II. <u>Discussion</u>

8. The Commission denies the requests for rehearing, for the reasons discussed below.

A. Implementation Plan

Order No. 830

9. In Order No. 830, the Commission approved the phased, five-year implementation plan proposed by NERC. Under the approved implementation plan, Requirement R1 of Reliability Standard TPL-007-1 will become effective on the first day of the first calendar quarter that is six months after Commission approval. Requirement R2 will become effective on the first day of the first calendar quarter that is 18 months after Commission approval. Requirement R5 will become effective on the first day of the first calendar quarter that is 24 months after Commission approval. Requirement R6 will become effective on the first day of the first calendar quarter that is 48 months after Commission approval. And Requirement R3, Requirement R4, and Requirement R7 will become effective on the first day of the first calendar quarter that is 60 months after Commission approval.

Request

10. EEI contends that the Commission erred by approving NERC's implementation plan without accounting for the impacts of the directives contained in Order No. 830 concerning modifications to Reliability Standard TPL-007-1. Specifically, EEI disagrees with the Commission's statement that the approved implementation plan should afford enough time to apply the revised benchmark GMD event definition in the first GMD Vulnerability Assessment. EEI maintains that the "impacts [of revising the benchmark GMD event definition in Reliability Standard TPL-007-1] are not nearly so inconsequential because the benchmark GMD event definition serves as an input upon which several Requirements build, including requirements whose effective dates arrive earlier than the vulnerability assessments required by Requirement R4, and which are effective January 1, 2022."[5]

11. EEI also states that the Commission "should reiterate that prudent expenditures by all Responsible Entities in compliance with TPL-007-1, even if analyses need to be performed again, will be recoverable, whether through formula transmission rates, single issue ratemaking for those who have stated rates or a rider for generators in competitive markets."[6]

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[5] EEI Request at 6.

[6] *Id.* at 10.

Commission Determination

12. We deny EEI's request for rehearing regarding the approved implementation plan. In Order No. 830, the Commission recognized the possibility that the modifications to Reliability Standard TPL-007-1 directed by the Commission might require Reliability Standard TPL-007-1and the revised Reliability Standard to be implemented on a longer schedule than the schedule approved in Order No. 830.[7] Specifically, the Commission stated in Order No. 830 that, "[i]f circumstances, such as the complexity of the revised benchmark GMD event, require it, NERC may propose and justify a revised implementation plan."[8] At this time, the Commission has no way of knowing what impacts the modified benchmark GMD event definition may have on the approved implementation plan because NERC has not yet developed or proposed a revised Reliability Standard.[9] Accordingly, EEI's concern is premature. At an appropriate time, as the Commission indicated in Order No. 830, NERC may propose and justify a revised implementation plan if a longer schedule is warranted by the modifications to Reliability Standard TPL-007-1.

13. The Commission affirms the statement in Order No. 830 that "cost recovery for prudent costs associated with or incurred to comply with Reliability Standard TPL-007-1 and future revisions to the Reliability Standard will be available to registered entities."[10]

B. GMD Vulnerability and Thermal Impact Assessments

Order No. 830

14. In Order No. 830, the Commission approved the benchmark GMD event definition, including the reference peak geoelectric field amplitude figure, proposed by NERC. In addition, the Commission directed NERC to develop revisions to the benchmark GMD event definition so that the reference peak geoelectric field amplitude component is not based solely on spatially-averaged data. Similarly, the Commission directed NERC to modify Reliability Standard TPL-007-1 to require registered entities to

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[7] EEI's request acknowledges the language in Order No. 830 regarding the possibility of modifications to the implementation plan. *See id.* at 7 n.15.

[8] Order No. 830, 156 FERC ¶ 61,215 at P 50.

[9] EEI states that Requirements R1 and R2 of Reliability Standard TPL-007-1 could be completed without being impacted by the directed modifications to the Reliability Standard. EEI Request at 10.

[10] Order No. 830, 156 FERC ¶ 61,215 at P 24.

apply spatially averaged and non-spatially averaged peak geoelectric field values, or some equally efficient and effective alternative, when conducting thermal impact assessments.

Request

15. Resilient Societies contends that the Commission erred by not addressing several features of Reliability Standard TPL-007-1. First, Resilient Societies maintains that the Commission did not consider "prudent design factors" to account for the uncertainties surrounding GMDs. In particular, Resilient Societies contends that the Commission erred by failing to apply a "safety factor," such as a "multiplier in the range from two to four … to the anticipated geo-electric field for an extreme [GMD] impact."[11] Second, Resilient Societies argues that the Commission did not address Resilient Societies' comments on: (1) the need to consider GMD hazards from "vibration impacts on transformers" and (2) the "arbitrary" exemption of networks operating between 100 kV and 200kV from the applicability section of Reliability Standard TPL-007-1.

Commission Determination

16. We deny Resilient Societies' request for rehearing on these issues.

17. With respect to the consideration of "prudent design factors," the Commission, in Order No. 830, acknowledged the uncertainties regarding GMDs in terms of each of the components of the benchmark GMD event (i.e., the reference peak geoelectric field amplitude, local geomagnetic latitude scaling factor and local earth conductivity scaling factor). The Commission concluded that Reliability Standard TPL-007-1 provided an adequate technical basis from which to approve the Reliability Standard pursuant to FPA section 215(d)(2). To address the uncertainties regarding the reference peak geoelectric field amplitude and local geomagnetic latitude and earth conductivity scaling factors, the Commission directed NERC to study those issues as part of the GMD research work plan.[12] For example, the Commission specifically directed NERC to study "coastal effects" on ground conductivity models.[13] Having determined that NERC provided an adequate technical basis from which to approve Reliability Standard TPL-007-1, we do not believe it would be appropriate to require an additional, arbitrary "design factor for uncertainty." Instead, the Commission determined in Order No. 830, and affirms here,

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[11] Resilient Societies' Request at 6.

[12] Order No. 830, 156 FERC ¶ 61,215 at PP 76-81.

[13] *Id.* P 78.

that improving our understanding of GMDs through the GMD research work plan will provide a scientific foundation for improvements to Reliability Standard TPL-007-1.[14]

18. Regarding Resilient Societies' concerns about vibration impacts on transformers, in Order No. 830, the Commission recognized that transformers could be damaged or otherwise affected by a GMD event other than through transformer heating. The Commission noted that NERC's comments indicated that NERC was "collaborating with researchers to examine more complex GMD vulnerability issues, such as harmonics and mitigation assessment techniques, to enhance the modeling capabilities of the industry."[15] In response, the Commission directed NERC to study the broader issue of transformer impacts as part of the GMD research work plan.[16] We also note that Reliability Standard TPL-007-1, in addition to requiring thermal impact assessments of qualifying transformers, also requires, in Requirement R4, System studies as part of the GMD Vulnerability Assessments.[17]

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[14] The NERC standard drafting team's selection of 8 V/km for the reference peak geoelectric field amplitude was based on a possible range of between 3 and 8 V/km with "the upper limit of the 95% confidence interval for a 100-year return level … [being] more precisely 5.77 V/km." NERC Petition, Ex. D (White Paper on GMD Benchmark Event Description) at 10.

[15] Order No. 830, 156 FERC ¶ 61,215 at P 68 n.101. Dr. Horton, a member of the standard drafting team, discussed the potential negative impacts of harmonics generated by GMDs on protection systems, reactive power resources and generators. *Id.* P 68 n.100 (citing Slide Presentation of Randy Horton, March 1, 2016 Technical Conference at 2-6). In prepared remarks at the March 1, 2016 Technical Conference, Dr. Horton explained that, "Transformer noise and vibration is created by a phenomenon called magnetorestriction …[and] [h]armonic currents created by half-cycle saturation cause magnetorestriction in the core." Statement of Randy Horton, March 1, 2016 Technical Conference at 11-12.

[16] Order No. 830, 156 FERC ¶ 61,215 at P 68 ("we direct NERC to address the effects of harmonics, including tertiary winding harmonic heating and any other effects on transformers, as part of the GMD research work plan").

[17] Reliability Standard TPL-007-1, Requirement 4.2 ("The study or studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the System meets the performance requirements in Table 1."). The NERC Glossary of Terms defines System as a "combination of generation, transmission, and distribution components."

19. With respect to the applicability criteria for Reliability Standard TPL-007-1, the Commission addressed this issue in Order No. 797 when approving the First Stage GMD Reliability Standard EOP-010-1. As the Commission observed in Order No. 830, NERC explained that Reliability Standards EOP-010-1 and TPL-007-1 purposefully use the same applicability criteria to determine the types of transformers that are subject to the Reliability Standards (i.e., power transformer(s) with a high side, wye grounded winding with terminal voltage greater than 200 kV).[18] Resilient Societies' comments offer no basis for revisiting that determination, particularly since the information contained in Resilient Societies' comments is directed to reactive power facilities operating below 200 kV rather than to transformers.[19]

C. <u>GMD-Related Data</u>

<u>Order No. 830</u>

20. In Order No. 830, the Commission determined that additional collection and disclosure of GIC monitoring and magnetometer data is necessary to improve our collective understanding of the threats posed by GMD events. The Commission directed NERC to develop revisions to Reliability Standard TPL-007-1 to require applicable entities to collect GIC monitoring and magnetometer data as necessary to enable model validation and situational awareness, including from any devices that must be added to meet this need. The Commission also directed NERC, pursuant to Section 1600 of the NERC Rules of Procedure, to collect GIC monitoring and magnetometer data from registered entities for the period beginning May 2013, including both data existing as of the date of Order No. 830 and new data going forward, and to make that information available. The Commission further explained that, as a general matter, the Commission does not believe that GIC monitoring and magnetometer data should be treated as Confidential Information pursuant to the NERC Rules of Procedure.

<u>Requests</u>

21. JINSA maintains that Reliability Standard TPL-007-1 should be modified to require "collection and public disclosure of relevant data on grid impacts during GMD events and incorporation of these data into any future revisions of GMD standards."[20]

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[18] Order No. 830, 156 FERC ¶ 61,215 at P 10; *see also* NERC Petition at 14.

[19] Resilient Societies' Comments at 47-52.

[20] JINSA Request at 3.

22. CSP contends that the standard drafting team "failed to collect relevant data, contrary to Section 6.0 of the NERC Standards Processes Manual … NERC did not collect available data on [GIC] and transformer failures, making effective quality control impossible."[21]

23. Resilient Societies contends that the Commission erred by not requiring the collection and disclosure of "impacts of solar storms" and, thus, "the impacts of solar storms on electric grids … [will] remain hidden from public view."[22] Resilient Societies also asserts that the Commission erred by not requiring the collection and disclosure of GIC monitoring and magnetometer data in existence prior to May 2013. Lastly, Resilient Societies contends that the Commission should have required that "utilities annually disclose mitigative measures" for transformers.[23]

Commission Determination

24. We deny the requests for rehearing on these issues.

25. In Order No. 830, the Commission addressed the issues raised by JINSA and Resilient Societies regarding the collection and public availability of GMD-related data by directing NERC: (1) to modify Reliability Standard TPL-007-1 to require the collection of necessary GIC monitoring data and magnetometer data and to make such data publicly available; and (2) pursuant to Section 1600 of the NERC Rules of Procedure, to collect GIC monitoring and magnetometer data from registered entities for the period beginning May 2013 forward. The Commission explained that additional collection and disclosure of GIC monitoring and magnetometer data is "necessary to improve our collective understanding of the threats posed by GMD events" and "will facilitate a greater understanding of GMD events that, over time, will improve Reliability Standard TPL-007-1."[24]

26. The Commission required NERC to collect GMD data pursuant to Section 1600 of the NERC Rules of Procedure from May 2013 forward because Order No. 779, which directed NERC to develop the GMD Reliability Standards, issued on May 16, 2013. Given the burdens associated with collecting data under the NERC Rules of Procedure, we believe it is reasonable to limit the temporal scope of the directive to the date of

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[21] CSP Request at 3.

[22] Resilient Societies' Request at 4.

[23] *Id.*

[24] Order No. 830, 156 FERC ¶ 61,215 at PP 88, 93.

issuance of Order No. 779. However, nothing in Order No. 830 precludes NERC from collecting data from before May 2013 and, indeed, we encourage NERC to collect and make available as much relevant data as it can.[25]

27. To the extent that JINSA and Resilient Societies contend that the Commission should require the collection of "GMD impact" data beyond collecting GIC monitoring data and magnetometer data, we disagree. As the Commission explained in Order No. 830, the intent in collecting GIC monitoring and magnetometer data is to enable model validation and situational awareness. Reliability Standard TPL-007-1, which is a planning Reliability Standard, is intended to maintain system planned performance during GMD events by assessing the vulnerability of Bulk-Power System components to a benchmark GMD event and mitigating any assessed vulnerabilities.[26] Nonetheless, we expect utilities to consider any actual impacts in assessing and mitigating their vulnerabilities, and we may request such information in the future, if and when warranted.

28. In addition, regarding Resilient Societies' request that "utilities annually disclose mitigative measures" for transformers, we see no need for such a requirement. To the extent that an applicable entity determines that a qualifying transformer is vulnerable to a benchmark GMD event, Reliability Standard TPL-007-1, Requirement R7 requires the development of a corrective action plan to mitigate the vulnerability. As indicated in the corresponding Measure for Requirement R7, to demonstrate compliance, "[e]ach responsible entity … shall have evidence such as electronic or hard copies of its Corrective Action Plan, as specified in Requirement R7." Compliance enforcement entities (i.e., the Commission, NERC and Regional Entities) will therefore have the ability to assess the number of qualifying transformers undergoing corrective action plans.

29. We disagree with CSP that the NERC standard drafting team violated Section 6.0 of the NERC Standards Processes Manual in collecting data used to derive the benchmark GMD event definition. As the Commission indicated in Order No. 830, there is no evidence of procedural irregularities or of the standard drafting team's failure to comply with the NERC Rules of Procedure.[27] Instead, we view the allegations contained

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[25] Resilient Societies states that the Commission should require "disclosure of all relevant GIC data in possession of the EPRI Sunburst program." Resilient Societies Request at 15. However, EPRI, a non-profit research institution, is not a user, owner or operator of the Bulk-Power System and, therefore, is outside of the Commission's jurisdiction under section 215 of the FPA.

[26] Reliability Standard TPL-007-1, Purpose, Requirements R4 and R7.

[27] Order No. 830, 156 FERC ¶ 61,215 at P 123.

in the NERC "Level 2" Appeal as an inappropriate vehicle to challenge the substantive provisions of Reliability Standard TPL-007-1, which the Commission addressed in Order No. 830.

D. <u>Other Requests</u>

30. JINSA and CSP maintain that Order No. 830 should have addressed the threats posed by electromagnetic pulses (EMPs) or otherwise raise the issue of EMPs. However, the Commission has indicated before, first in directing the development of GMD Reliability Standards in Order No. 779; then in approving the First Stage GMD Reliability Standards in Order No. 797; and most recently in Order No. 830, that EMPs are not within the scope of the GMD rulemaking proceedings.[28] While the risk from EMPs and any appropriate mitigation continues to be analyzed by EPRI and others, and we continue to monitor those important activities, this proceeding is not the proper forum for regulatory action on the issue.

31. CSP contends that two documents, a presentation by Dr. Adam Schultz of Oregon State University and a report by Los Alamos National Laboratory, were "withheld from public view and from the FERC docket."[29] CSP's contention is without merit. Dr. Schultz participated in the staff-led GMD technical conference held on March 1, 2016 and submitted for the record materials regarding his research, including a presentation entitled "Electric fields at ground level due to GMDs: Accounting for realworld 3-D ground conductivity effects."[30] With respect to the Los Alamos National Laboratory report, the Commission issued a notice on October 2, 2015 seeking comment on the September 2015 technical paper prepared by the Los Alamos National Laboratory entitled "Review of the GMD Benchmark Event in TPL-007-1."[31] In addition, Dr. Scott Backhaus, one of the two named authors of the Los Alamos National Laboratory report, participated in and submitted for the record materials as part of the staff-led GMD technical conference held on March 1, 2016.

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[28] *Id.* P 119 (citing Order No. 779, 143 FERC ¶ 61,209 and 797, 147 FERC ¶ 61,209).

[29] CSP Request at 2.

[30] A link to the presentation referenced by CSP was filed in the Commission's eLibrary document retrieval system in Docket No. RM15-11-000 on September 31, 2015, prior to the technical conference.

[31] The Los Alamos National Laboratory report was both publicly available and filed in the Commission's eLibrary document retrieval system in Docket No. RM15-11-000 on September 30, 2015.

32. JINSA maintains that the Commission should grant rehearing to "incorporate determinations of the U.S. Department of Energy Pilot Program to demonstrate and assess grid-protective devices pursuant to Section 5(a) of Executive Order No. 13744 issued by the President on October 12, 2016."[32] As explained in Order No. 830, Reliability Standard TPL-007-1 requires applicable entities to mitigate any assessed vulnerabilities to a benchmark GMD event. The Reliability Standard does not, however, mandate any specific form of mitigation provided the vulnerability is mitigated. Accordingly, to the extent JINSA requests that the Commission require the adoption of specific forms of mitigation stemming from Section 5(a) of Executive Order No. 13744, we decline to do so here. However, just as the Commission in Order No. 830 indicated that NERC's GMD research should be informed by ongoing GMD-related research efforts by government agencies, laboratories and academia, we expect that the required mitigation of GMD vulnerabilities will be informed by efforts such as those set out in Section 5(a) of Executive Order No. 13744.

33. JINSA states that "modifications of Standard TPL-007-1 … [should] include … [a] cost-benefit analysis that includes the specific analysis of societal impacts of grid damage."[33] We see no need for NERC to conduct the requested cost-benefit analysis. Reliability Standard TPL-007-1 was developed in response to the Commission's directive in Order No. 779 regarding the Second Stage GMD Reliability Standards. The Commission based its directive on the potentially severe, widespread impact on the reliable operation of the Bulk-Power System that can be caused by GMD events and the then absence of existing Reliability Standards to address GMD events. In determining the benchmark GMD event used in Reliability Standard TPL-007-1, NERC provided an adequate technical basis for using a 1-in-100 year GMD event to define the benchmark GMD event. We do not believe that JINSA's assertion "that an assessment of the value of societal losses caused by major GMD events … will be important in order to justify protection costs" is relevant to the question of whether Reliability Standard TPL-007-1 satisfies the statutory criteria for approval of Reliability Standards set forth in FPA section 215(d)(2).[34]

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[32] JINSA Request at 3. Section 5(a) of Executive Order No. 13744 states in relevant part that, "Within 120 days of the date of this order, the Secretary of Energy, in consultation with the Secretary of Homeland Security, shall develop a plan to test and evaluate available devices that mitigate the effects of geomagnetic disturbances on the electrical power grid through the development of a pilot program that deploys such devices, in situ, in the electrical power grid. After the development of the plan, the Secretary shall implement the plan in collaboration with industry."

[33] JINSA Request at 3.

[34] *Id.*

34. We reject Resilient Societies' request regarding the "Initial Actions" assessments discussed in Order No. 779 as untimely.[35]

The Commission orders:

The Commission denies the rehearing requests, for the reasons discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

[35] Order No. 779 did not require NERC to make any filings regarding the "Initial Actions" assessments. Instead, the Commission indicated that the "'Initial Actions' assessments provide a head start for analyzing the most at-risk and critical facilities before the Second Stage GMD Reliability Standards become effective and could be used to assist in performing the GMD vulnerability assessments required in the Second Stage GMD Reliability Standards." Order No. 779, 143 FERC ¶ 61,147 at P 52.

158 FERC ¶ 61,030
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM16-7-000; Order No. 835]

Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event Reliability Standard

(Issued January 19, 2017)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Commission approves Reliability Standard BAL-002-2 (Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event) submitted by the North American Electric Reliability Corporation (NERC). Reliability Standard BAL-002-2 is designed to ensure that balancing authorities and reserve sharing groups balance resources and demand and return their Area Control Error to defined values following a Reportable Balancing Contingency Event. In addition, the Commission directs NERC to develop modifications to Reliability Standard BAL-002-2 to address concerns regarding extensions of the 15-minute period for Area Control Error recovery and contingency reserve restoration. The Commission also directs NERC: (1) to collect and report on data regarding additional megawatt losses following Reportable Balancing Contingency Events during the Contingency Reserve Restoration Period; and (2) to study and report on the reliability risks associated with megawatt losses above the most severe single contingency that do not cause energy emergencies.

EFFECTIVE DATE: This rule will become effective **[INSERT DATE 60 days after publication in the FEDERAL REGISTER**].

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SUPPLEMENTARY INFORMATION:

158 FERC ¶ 61,030
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, and Colette D. Honorable.

Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event Reliability Standard — Docket No. RM16-7-000

ORDER NO. 835

FINAL RULE

(Issued January 19, 2017)

1. Pursuant to section 215 of the Federal Power Act (FPA),[1] the Commission approves Reliability Standard BAL-002-2 (Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event). The North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), developed and submitted Reliability Standard BAL-002-2 for Commission approval. Reliability Standard BAL-002-2 is intended to ensure that balancing authorities and reserve sharing groups are able to recover from system contingencies by deploying adequate reserves to return their Area Control Error (ACE) to defined values and by replacing the capacity and energy lost due to generation or

[1] 16 U.S.C. 824(o).

transmission equipment outages.[2] In addition, the Commission approves eight new and revised definitions proposed by NERC for inclusion in the NERC Glossary and the retirement of currently-effective Reliability Standard BAL-002-1 immediately prior to the effective date of Reliability Standard BAL-002-2. The Commission also approves, with one modification, Reliability Standard BAL-002-2's associated violation risk factors and violation severity levels, and implementation plan.

2. Pursuant to section 215(d)(5) of the FPA,[3] the Commission directs NERC to develop modifications to Reliability Standard BAL-002-2, Requirement R1 to address concerns related to the potential reliability impact of repeated extensions of the period for ACE recovery. To address the concerns, the Notice of Proposed Rulemaking (NOPR) proposed directing that NERC modify the Reliability Standard to require reliability coordinator approval of extensions of the ACE recovery period. Numerous commenters opposed the proposal, arguing that the proposal has the potential to complicate an already challenging situation. Thus, to address the underlying concern while cognizant of the NOPR comments, the final rule adopts a different approach of directing NERC to develop modifications to Reliability Standard BAL-002-2 that would require an entity to

[2] ACE is the instantaneous difference between a balancing authority's Net Actual and Scheduled Interchange, taking into account the effects of Frequency Bias, correction for meter error, and Automatic Time Error Correction (ATEC), if operating in ATEC mode. ATEC is only applicable to balancing authorities in the Western Interconnection. NERC Glossary of Terms Used in NERC Reliability Standards (NERC Glossary) at 7 (updated September 29, 2016).

[3] 16 U.S.C. 824o(d)(5).

provide certain information to the reliability coordinator when the entity does not timely recover ACE due to an intervening disturbance. As discussed below, the Commission also directs NERC: (1) to collect and report on data related to resets of the contingency reserve restoration period; and (2) to study and report on the reliability risks associated with megawatt losses above an applicable entity's most severe single contingency (MSSC) that do not cause energy emergencies.

I. Background

3. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards that are subject to Commission review and approval. 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.[4] Once approved, the Reliability Standards may be enforced by NERC, subject to Commission oversight, or by the Commission independently.[5] Pursuant to section 215 of

[4] *Id.* 824o(d)(2).

[5] *Id.* 824o(e).

the FPA, the Commission established a process to select and certify an ERO,[6] and subsequently certified NERC.[7]

4. On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 Reliability Standards filed by NERC, including Reliability Standard BAL-002-0.[8] In addition, pursuant to section 215(d)(5) of the FPA, the Commission directed the ERO to develop modifications to Reliability Standard BAL-002-0: (1) to include a requirement that explicitly provides that demand side management may be used as a resource for contingency reserves; (2) to develop a continent-wide contingency reserve policy; and (3) to refer to the ERO rather than the NERC Operating Committee in Requirements R4.2 and R6.2.[9] On January 10, 2011, the Commission approved Reliability Standard BAL-002-1, which addressed the third directive described above.[10]

[6] *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).

[7] *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 1342 (D.C. Cir. 2009).

[8] *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).

[9] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 356.

[10] *North American Electric Reliability Corp.*, 134 FERC ¶ 61,015 (2011).

II. NERC Petition and Reliability Standard BAL-002-2

5. On January 29, 2016, NERC filed a petition seeking approval of Reliability Standard BAL-002-2;[11] eight new or revised definitions to be added to the NERC Glossary; and Reliability Standard BAL-002-2's associated violation risk factors and violation severity levels, effective date, and implementation plan.[12] NERC stated that Reliability Standard BAL-002-2 is just, reasonable, not unduly discriminatory or preferential, and in the public interest because it satisfies the factors set forth in Order No. 672, which the Commission applies when reviewing a proposed Reliability Standard.[13] NERC also asserted that Reliability Standard BAL-002-2 addresses the outstanding directives from Order No. 693 regarding the use of demand side management as a resource for contingency reserve and the development of a continent-wide contingency reserve policy.

6. Reliability Standard BAL-002-2 consolidates six requirements in currently-effective Reliability Standard BAL-002-1 into three requirements and is applicable to

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[11] Reliability Standard BAL-002-2 is available on the Commission's eLibrary document retrieval system in Docket No. RM16-7-000 and on the NERC website, www.nerc.com.

[12] The eight proposed new and revised definitions for inclusion in the NERC Glossary are for the following terms: Balancing Contingency Event, Most Severe Single Contingency, Reportable Balancing Contingency Event, Contingency Event Recovery Period, Contingency Reserve Restoration Period, Pre-Reporting Contingency Event ACE Value, Reserve Sharing Group Reporting ACE, and Contingency Reserve. NERC Petition at 28-34.

[13] NERC Petition at 13 and Ex. F (Order No. 672 Criteria).

balancing authorities and reserve sharing groups. NERC stated that Reliability Standard BAL-002-2 improves upon existing Reliability Standard BAL-002-1 because "it clarifies obligations associated with achieving the objective of BAL-002 by streamlining and organizing the responsibilities required therein, enhancing the obligation to maintain reserves, and further defining events that predicate action under the standard."[14] NERC also stated that Reliability Standard BAL-002-2 "address[es] and supersede[s]" the proposed interpretation previously submitted by NERC (i.e., of Reliability Standard BAL-002-1a) and pending in Docket No. RM13-6-000.[15]

7. Requirement R1 of BAL-002-2 requires a balancing authority or reserve sharing group experiencing a Reportable Balancing Contingency Event to deploy its contingency reserves to recover its ACE to certain prescribed values within the Contingency Event

[14] *Id.* at 13.

[15] *Id.* at 1. On February 12, 2013, NERC filed a proposed interpretation of Reliability Standard BAL-002-1 that construed the Reliability Standard so that the 15-minute ACE recovery period would not apply to events of a magnitude exceeding an entity's most severe single contingency. In a NOPR issued on May 16, 2013, the Commission proposed to remand the proposed interpretation on procedural grounds. *Electric Reliability Organization Interpretation of Specific Requirements of the Disturbance Control Performance Standard*, 143 FERC ¶ 61,138 (2013). The rulemaking on the proposed interpretation is pending. In the petition in the immediate proceeding, NERC states that, upon approval of Reliability Standard BAL-002-2, NERC will file a notice of withdrawal of the proposed interpretation. NERC Petition at 1.

Recovery Period of 15 minutes.[16] However, under certain circumstances, Reliability Standard BAL-002-2 relieves responsible entities from strict compliance with the existing time periods for ACE recovery and contingency reserve restoration "to ensure responsible entities retain flexibility to maintain service to Demand, while managing reliability, and to avoid duplication with other Reliability Standards."[17]

8. Specifically, Requirement R1, Part 1.3.1 provides that a balancing authority or reserve sharing group is not subject to Requirement R1, Part 1.1 if it: (1) is experiencing a Reliability Coordinator declared Energy Emergency Alert Level; (2) is utilizing its contingency reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and (3) has depleted its contingency reserve to a level below its most severe single contingency.

9. In addition, under Requirement R1, Part 1.3.2, a balancing authority or reserve sharing group is not subject to Requirement R1, Part 1.1 if the balancing authority or

[16] NERC proposes to define Reportable Balancing Contingency Event as: "Any Balancing Contingency Event occurring within a one-minute interval of an initial sudden decline in ACE based on EMS scan rate data that results in a loss of MW output less than or equal to the Most Severe Single Contingency, and greater than or equal to the lesser amount of: (i) 80% of the Most Severe Single Contingency, or (ii) the amount listed below for the applicable Interconnection. Prior to any given calendar quarter, the 80% threshold may be reduced by the responsible entity upon written notification to the Regional Entity." NERC Petition at 30. Contingency Event Recovery Period, as proposed by NERC, means: "A period that begins at the time that the resource output begins to decline within the first one-minute interval of a Reportable Balancing Contingency Event, and extends for fifteen minutes thereafter." *Id.* at 32.

[17] *Id.* at 4.

reserve sharing group experiences: (1) multiple Contingencies where the combined megawatt (MW) loss exceeds its most severe single contingency and that are defined as a single Balancing Contingency Event or (2) multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's most severe single contingency.

10. Requirement R2 provides that each responsible entity:

> shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and to make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability.

NERC explained that Requirement R2 requires responsible entities to demonstrate that their process for calculating their most severe single contingency "surveys all contingencies, including single points of failure, to identify the event that would cause the greatest loss of resource output used by the [reserve sharing group or balancing authority] to meet Firm Demand."[18] NERC further stated that Requirement R2 supports Requirements R1 and R3 in Reliability Standard BAL-002-2 "as these requirements rely on proper calculation of [most severe single contingency]."[19]

[18] *Id.* at 25.

[19] *Id.* NERC provides examples of how responsible entities may calculate the most severe single contingency in the petition. *See* NERC Petition, Ex. B (Calculating Most Severe Single Contingency).

11. Requirement R3 provides that "each Responsible Entity, following a Reportable Balancing Contingency Event, shall restore its Contingency Reserve to at least its Most Severe Single Contingency, before the end of the Contingency Reserve Restoration Period [90 minutes], but any Balancing Contingency Event that occurs before the end of a Contingency Reserve Restoration Period resets the beginning of the Contingency Event Recovery Period."

12. NERC explained that the revised language in the consolidated requirements in Reliability Standard BAL-002-2 will improve efficiency and clarity by removing "unnecessary entities from compliance to capture only those entities that are vital for reliability."[20] NERC stated that the new definitions for Balancing Contingency Event and Reportable Balancing Contingency Event more clearly identify the types of events that cause frequency deviations necessitating action under Reliability Standard BAL-002-2 and provide additional detail regarding the types of resources that may be identified as contingency reserves. Furthermore, NERC stated that Reliability Standard BAL-002-2 "ensures objectivity of the reserve measurement process by guaranteeing a Commission-sanctioned continent-wide reserve policy," and therefore satisfies an outstanding Order No. 693 directive for uniform elements, definitions and requirements for a continent-wide contingency reserve policy.[21] Finally, NERC asserted that the revised definition of

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[20] NERC Petition at 14.

[21] *Id.*

Contingency Reserves "improves the existing definition by addressing a Commission directive in Order No. 693 to allow demand side management to be used as a resource for contingency reserve when necessary."[22]

13. NERC submitted proposed violation risk factors and violation severity levels for each requirement of Reliability Standard BAL-002-2 and an implementation plan and effective dates. NERC stated that these proposals were developed and reviewed for consistency with NERC and Commission guidelines. NERC proposed an effective date for Reliability Standard BAL-002-2 that is the first day of the first calendar quarter that is six months after the date of Commission approval. NERC explained that this implementation date will allow entities to make necessary modifications to existing software programs to ensure compliance.[23]

14. On February 12, 2016, NERC submitted a supplemental filing to clarify a statement in the petition that Reliability Standard BAL-002-2 would operate in conjunction with Reliability Standard TOP-007-0 to control system frequency by addressing transmission line loading in the event of a transmission overload. NERC explained that, while Reliability Standard TOP-007-0 will be retired on April 1, 2017, "the obligations related to [transmission line loading] under TOP-007-0 will be covered by Commission-approved TOP-001-3, EOP-003-2, IRO-009-2, and IRO-008-2 . . . by

[22] *Id.* at 33.

[23] NERC Petition, Ex. D (Implementation Plan) at 3.

requiring relevant functional entities to communicate [Interconnection Reliability Operating Limits (IROL)] and [System Operating Limits (SOL)] exceedances so that the [reliability coordinator] can direct appropriate corrective action to mitigate or prevent those events."[24]

15. On March 31, 2016, NERC submitted a second supplemental filing to "further clarify the extent to which BAL-002-2 interacts with other Commission-approved Reliability Standards to promote Bulk Power System reliability…[and support] the overarching policy objective reflected in the stated purpose of Reliability Standard BAL-002-2."[25] In its filing, NERC expanded upon the explanation in the petition regarding how an "integrated" and "coordinated suite of Reliability Standards" (BAL-001-2, BAL-003-1, TOP-007-0, EOP-002-3, EOP-011-1, IRO-008-2, and IRO-009-2) will apply to events causing MW losses above a responsible entity's most severe single contingency, and how those other Reliability Standards are better designed to manage the greater risks created by such events.[26]

III. Notice of Proposed Rulemaking

16. On May 19, 2016, the Commission issued a NOPR proposing to approve Reliability Standard BAL-002-2 as just, reasonable, not unduly discriminatory or

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[24] NERC February 12, 2016 Supplemental Filing at 2-3.

[25] NERC March 31, 2016 Supplemental Filing at 1, 5.

[26] *Id.* at 2-5.

preferential and in the public interest.[27] The Commission also proposed to approve NERC's eight proposed new and revised definitions and the retirement of currently-effective Reliability Standard BAL-002-1. Further, the Commission proposed to direct NERC to change the proposed violation risk factor from "medium" to "high" for Reliability Standard BAL-002-2, Requirements R1 and R2.

17. In the NOPR, the Commission recognized that it is essential for grid reliability that responsible entities balance resources and demand and restore system frequency to recover from a system event, and that they maintain reserves necessary to replace capacity and energy lost due to generation or transmission outages. The Commission also stated that Reliability Standard BAL-002-2 improves upon currently-effective Reliability Standard BAL-002-1 by consolidating requirements to streamline and clarify the obligations related to achieving these goals. However, the Commission raised concerns regarding possible extensions of the 15-minute ACE recovery period and the 90-minute Contingency Reserve Restoration Period, as well as NERC's proposal to limit the scope of Reliability Standard BAL-002-2 to a responsible entity's most severe single contingency.

18. In the NOPR, the Commission sought comment on the following issues: (1) reliability coordinator authorization of extensions of the 15-minute ACE recovery period; (2) resets or credits during the 90-minute Contingency Reserve Restoration

[27] *Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event Reliability Standard*, Notice of Proposed Rulemaking, 81 FR 33,441 (May 26, 2016), 155 FERC ¶ 61,180 (2016) (NOPR).

Period; (3) the exclusion of megawatt losses above the most severe single contingency in the proposed definition of Reportable Balancing Contingency Event; and (4) NERC's proposal to reduce from "high" to "medium" the violation risk factor for proposed Requirements R1 and R2. The Commission also sought comment on whether NERC's proposed definition of contingency reserve should include the NERC-defined term Demand-side Management.

19. In response to the NOPR, the Commission received 11 sets of comments. We address below the issues raised in the NOPR and comments. The Appendix to this final rule lists the entities that filed comments in response to the NOPR.

IV. Discussion

20. Pursuant to FPA section 215(d)(2), we approve Reliability Standard BAL-002-2 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. We also approve NERC's eight new and revised proposed definitions and, with one exception, the proposed violation risk factor and violation severity level assignments. In addition, we approve NERC's implementation plan establishing an effective date of the first day of the first calendar quarter, six months after the date of Commission approval, and the retirement of currently-effective BAL-002-1 immediately before that date.[28]

21. The purpose of Reliability Standard BAL-002-2 is to ensure that balancing authorities and reserve sharing groups balance resources and demand and return their

[28] NERC Petition, Ex. D (Implementation Plan) at 3.

ACE to defined values following a Reportable Balancing Contingency Event. We determine that Reliability Standard BAL-002-2 improves upon currently-effective Reliability Standard BAL-002-1 by consolidating the number of requirements to streamline and clarify the obligations for responsible entities to deploy contingency reserves to stabilize system frequency in response to system contingencies.

22. We conclude that BAL-002-2 satisfies the Order No. 693 directive that NERC develop a continent-wide contingency reserve policy.[29] Also, we accept NERC's explanation in response to the NOPR that demand side resources that are technically capable can be included as contingency reserves, and therefore determine that Reliability Standard BAL-002-2 satisfies the Order No. 693 directive that demand side management may be used as a resource for contingency reserves.[30]

23. In addition, pursuant to section 215(d)(5) of the FPA, we direct NERC to develop modifications to Reliability Standard BAL-002-2 to address our concerns, discussed below, regarding the 15-minute ACE recovery period set forth in Requirement R1. We also direct NERC to collect and report on data pertaining to the occurrence of Balancing Contingency Events that trigger resets of the 90-minute Contingency Reserve Restoration

[29] Order No. 693, FERC Stats. & Regs ¶ 31,242 at PP 340, 341 and 356.

[30] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 330, 335 and 356. In its comments NERC explained that "[t]he proposed definition balances the need for flexibility to include a variety of demand side resources in measurements of Contingency Reserve with the need to define the types of demand side resources that are 'technically capable' to serve as contingency reserve." NERC Comments at 30.

Period under Requirement R3. We further direct NERC to study and submit a report to the Commission with findings regarding reliability risks associated with most severe single contingency exceedances that do not result in energy emergencies.

24. We discuss below the following issues raised in the NOPR and addressed in the comments: (A) whether a reliability coordinator must expressly authorize extensions of the 15-minute ACE recovery period; (B) whether BAL-002-2 should be modified to require all contingency reserves to be restored within the 90-minute Contingency Reserve Restoration Period; (C) whether a reasonable obligation should be imposed for balancing authorities and reserve sharing groups to address scenarios involving megawatt losses above the most severe single contingency that do not cause energy emergencies; and (D) NERC's proposal to reduce from "high" to "medium" the violation risk factor for Requirements R1 and R2.

A. The 15-Minute ACE Recovery Period

NERC Petition

25. In its petition, NERC stated that the "exemption" from the 15-minute ACE recovery period in Requirement R1, Part 1.3.1 "eliminates the existing conflict with EOP-011-1, as it removes undefined auditor discretion when assessing compliance and allows the responsible entity flexibility to maintain service to load while managing reliability."[31] NERC explained that this exemption does not eliminate an entity's

[31] NERC Petition at 22.

obligation to respond to a Reportable Balancing Contingency Event, but rather it will "simply allow more time to return the Reporting ACE to the defined limits than would otherwise be allowed."[32]

NOPR

26. In the NOPR, the Commission noted that Reliability Standard BAL-002-2, Requirement R1 obligates a responsible entity that experiences a Reportable Balancing Contingency Event to return its Reporting ACE to pre-defined values within the 15-minute Contingency Event Recovery Period. Further, the Reliability Standard does not expressly provide a definitive and enforceable deadline for ACE recovery during a reliability coordinator-declared Energy Emergency Alert accompanied by the depletion of the entity's contingency reserves to below its most severe single contingency.

27. The Commission stated that NERC's explanation for relief from the 15-minute ACE recovery period in Reliability Standard BAL-002-2 raises concerns, because it is unclear how or when an entity will prepare for a second contingency during the indeterminate extension of the 15-minute ACE recovery period that Requirement R1, Part 1.3 permits. The Commission observed that a balancing authority that is operating out-of-balance for an extended period of time is "leaning on the system" by relying on external resources to meet its obligations. That could affect other entities within an Interconnection, particularly if another entity is reacting to a grid event while unaware

[32] *Id.* at 24.

that the first entity has not restored its ACE.[33] While an extension of the 15-minute ACE recovery period may be appropriate under certain emergency conditions, the NOPR explained that, with a wide-area view and superior information and objectivity, the reliability coordinator is in a better position to decide whether to extend the ACE recovery period after an entity has met the criteria described in Requirement R1, Part 1.3.1.

28. Further, while Reliability Standard EOP-011-1, Requirement R3, requires the reliability coordinator to review balancing authority Operating Plans and notify a balancing authority of any "reliability risks" the reliability coordinator may identify with a time frame for the resubmittal of revised Operating Plans, the NOPR explained that the Reliability Standard does not require reliability coordinator approval of Operating Plans.

29. Therefore, the NOPR proposed to direct NERC to develop modifications to Reliability Standard BAL-002-2 that would require Reporting ACE recovery within the 15-minute Contingency Event Recovery Period unless the relevant reliability coordinator expressly authorizes an extension of the 15-minute ACE recovery period after the balancing authority has met the criteria described in Requirement R1, Part 1.3.1. The Commission's proposal included modifying Reliability Standard BAL-002-2 to identify the reliability coordinator as an Applicable Entity.

[33] NOPR, 155 FERC ¶ 61,180 at P 22.

Comments

30. NERC, EEI, NRECA, TVA, CEA, Joint Commenters, IESO and APS oppose the proposed directive. NERC asserts that the proposed directive is unnecessary because the Balancing Authority ACE Limit (BAAL) and a balancing authority's resource obligations under Reliability Standard BAL-001-2 discourage balancing authorities from leaning on the system during extensions of the Contingency Event Recovery Period. NERC explains that the BAAL:

> is a unique limit on a [balancing authority's] Reporting ACE based on Real-time interconnection frequency levels … since the loss of a resource would influence the Interconnection's frequency, the BAAL would adjust (or 'tighten') to assure that the Interconnection frequency remains in a safe range. The [balancing authority] must return its operations to within the 'tightened' BAAL within 30 minutes and thus would not be able to 'lean' on the Interconnection for any prolonged period.[34]

31. Further, NERC contends that the proposed role for reliability coordinators is unnecessary—in both emergency and non-emergency situations—because the reliability coordinator "must maintain constant oversight of reliability within its [reliability coordinator] area and direct other responsible entities to take actions necessary to maintain reliability."[35]

32. EEI and Joint Commenters assert that the NOPR proposal "would result in unnecessary duplication of requirements adding no tangible benefit to reliability while

[34] NERC Comments at 10.

[35] *Id.* at 11 (citing Reliability Standards EOP-0011-1, EOP-003-2, IRO-001-4, IRO-002-4, IRO-008-2, and IRO-009-2).

needlessly increasing the compliance burden."[36] Joint Commenters also note the infrequent nature of multiple-contingency events and Energy Emergency Alerts (EEAs), describing them as "exceptional circumstances appropriate for an exemption from the typical measured requirements."[37] Joint Commenters state that in 2015 there were ten EEA Level 2 and Level 3 events, and that "most [balancing authorities] experience no EEA events in a given year ... allowing recovery exceptions during these exceptional circumstances would not create significant risk with respect to ACE recovery responsibilities."[38] Joint Commenters also contend that in a "multiple-contingency event or during an EEA, there are likely scores of activities occupying the [reliability coordinator's] attention. Requiring the [balancing authority] and [reliability coordinator] to conduct a conference call during an EEA to discuss the merits of requests for additional ACE recovery time only complicates these already-challenging conditions."[39]

33. While supporting the notification and involvement of reliability coordinators, APS shares Joint Commenters' concern that requiring reliability coordinators to expressly authorize extensions of the 15-minute ACE recovery period could distract responsible entities from focusing on "maintaining and recovering the reliability of the [bulk electric

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[36] EEI Comments at 7; *see also* Joint Commenters Comments at 2-4.

[37] Joint Commenters Comments at 4.

[38] *Id.* (citing NERC's 2016 State of Reliability Report at 38).

[39] *Id.* at 3.

system]."[40] Therefore, as an alternative to the NOPR proposal, APS proposes that balancing authorities obtain extensions of the 15-minute ACE recovery period under the extenuating circumstances described in Requirement R1, Part 1.3.1 by notifying the reliability coordinator of the conditions within its area and providing the reliability coordinator with an ACE recovery plan and target time period, but without obtaining express approval from the reliability coordinator.[41]

34. Idaho Power and BPA support the Commission's proposal to expressly require reliability coordinator authorization for extensions of the 15-minute Reporting ACE recovery period. Idaho power agrees with "shifting more oversight to the Reliability Coordinator" as the entity with the system-wide view.[42]

Commission Determination

35. We are persuaded by the commenters not to adopt the NOPR proposal that would require reliability coordinator authorization to extend the 15-minute ACE recovery period. As commenters explain, seeking the proposed reliability coordinator authorization while recovering from a disturbance has the potential to complicate an already-challenging situation. However, we continue to see a need to address the underlying concern expressed in the NOPR that a balancing authority that is operating

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[40] APS Comments at 4-5.

[41] *Id.* at 5.

[42] Idaho Power Comments at 2; *see also* BPA Comments at 3.

out-of-balance for an extended period of time is “leaning on the system” by relying on external resources to meet its obligations. That scenario could affect other entities within an Interconnection, particularly if another entity is reacting to a grid event while unaware that the first entity has not restored its ACE. Accordingly, to address our concern without requiring reliability coordinator authorization, we adopt APS’s proposed alternative that would require a balancing authority or reserve sharing group experiencing a depletion of contingency reserves below its most severe single contingency level during an Energy Emergency Alert to obtain an extension of the 15-minute ACE recovery period by informing the reliability coordinator of the circumstances and providing it with an ACE recovery plan and target time period.

36. We are persuaded that APS’s approach is reasonable and adequately addresses concerns with extensions of the 15-minute ACE recovery period. By requiring notification of reliability coordinators and providing the reliability coordinator with an ACE recovery plan and target time period, we agree that the APS proposal “would allow appropriate flexibility to [balancing authorities] when extenuating circumstances are present while providing [reliability coordinators] with the necessary data, communication, and coordination to fulfill their oversight responsibilities to the Interconnection.”[43]

[43] APS Comments at 8.

37. Accordingly, we direct NERC to develop modifications to Reliability Standard BAL-002-2, Requirement R1 to require balancing authorities or reserve sharing groups: (1) to notify the reliability coordinator of the conditions set forth in Requirement R1, Part 1.3.1 preventing it from complying with the 15-minute ACE recovery period; and (2) to provide the reliability coordinator with its ACE recovery plan, including a target recovery time. NERC may also propose an equally efficient and effective alternative.

B. The 90-Minute Contingency Reserve Restoration Period

NERC Petition

38. Reliability Standard BAL-002-2, Requirement R3 requires a balancing authority or reserve sharing group to restore its contingency reserves to at least its most severe single contingency before the end of the 90-minute Contingency Reserve Restoration Period.[44] Requirement R3 also provides for an automatic "reset" of the 90-minute restoration period based upon any Balancing Contingency Event that occurs during the restoration period.[45]

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[44] NERC Petition, Ex. D (Implementation Plan). The 90-minute contingency reserve restoration period begins after the end of the 15-minute ACE restoration period under Requirement R1. Accordingly, responsible entities must restore contingency reserves within 105 minutes of the occurrence of a Reportable Balancing Contingency Event to comply with Requirement R3.

[45] Balancing Contingency Event means: "Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by one minute or less.

(continued…)

NOPR

39. In the NOPR, the Commission proposed to direct NERC to modify Reliability Standard BAL-002-2 to "eliminate the potential for unlimited resets and ensure that contingency reserves must be restored within the 90-minute Contingency Reserve Restoration Period."[46] The Commission sought comment on a possible alternative that would give a balancing authority or reserve sharing group "credits" for megawatt losses resulting from Balancing Contingency Events during the 90-minute restoration period, and allow an additional 90 minutes to restore reserves related to those megawatt losses.[47]

Comments

40. NERC, EEI, NRECA, CEA, Joint Commenters, IESO and APS support approval of Requirement R3 as filed. NERC asserts that, because of resource limitations and the

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A. Sudden loss of generation:
  a. Due to
    i. unit tripping,
    ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or
    iii. sudden unplanned outage of transmission Facility;
  b. And, that causes an unexpected change to the responsible entity's ACE;
B. Sudden loss of an import, due to unplanned outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection.
C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE." NERC Petition Ex. D.

[46] NOPR, 155 FERC ¶ 61,180 at P 29.

[47] *Id.* PP 27-29.

potential compliance exposure to other Reliability Standards, including the Reporting ACE recovery requirements in Reliability Standard BAL-001-2, entities will not experience unlimited resets of the 90-minute restoration period.[48] NERC explains that "[i]f an entity continues to trip units before full recovery of other units, the responsible entity would eventually fail to meet obligations under other Reliability Standards (including the requirement to recover ACE within 15 minutes under proposed BAL-002-2) and may eventually enter into an Emergency situation under [reliability coordinator] oversight…"[49] NERC states that balancing authorities and reserve sharing groups would still be required to actively restore contingency reserves even after experiencing a Balancing Contingency Event during the 90-minute restoration period. Such events, according to NERC, "would merely extend the Contingency Reserve Restoration Period to ensure that the responsible entity has adequate time to recover from consecutive losses."[50] NERC asserts that the Commission's proposed credit approach "would be confusing and burdensome, and it may attract attention away from full and final restoration of the Contingency Reserve."[51] EEI agrees, adding that, "in light of existing

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[48] NERC Comments at 17-18.

[49] *Id.* at 17.

[50] *Id.* at 16.

[51] *Id.* at 18-19.

standards, this concern does not pose a sufficient risk to system reliability to merit NERC developing modifications to the standard."[52]

41. IESO and CEA claim that modifications to Reliability Standard BAL-002-2, Requirement R1 to eliminate the potential for unlimited resets are unnecessary. IESO questions the concern about unlimited resets of the Contingency Reserve Restoration Period, stating that it "would suggest that multiple resource loss events could somehow benefit or unburden a [balancing authority's] obligation to restore the reserve level … [rather] the infrequent event of a reset occurrence is more appropriately viewed as simply not applying double jeopardy to a [balancing authority] that is already in a troubled situation."[53] IESO further states that a reset of the contingency reserve restoration period "will simply provide the opportunity for the involved balancing authority to reassess the situation and act accordingly to replenish the contingency reserve" to comply with BAL-002-2.[54] Both IESO and CEA assert that balancing authorities "have a strong track record of acting in good faith."[55] CEA also notes that "since a [balancing authority] does

[52] EEI Comments at 8.

[53] IESO Comments at 4-5.

[54] *Id.* at 5; *see also* CEA Comments at 5.

[55] CEA Comments at 5; *see also* IESO Comments at 5.

not own any resources, it cannot trigger or otherwise intentionally cause an additional loss of resource during the 90-minute period in order to reset the recovery period."[56]

42. Joint Commenters also oppose the Commission's proposal, explaining that "following a unit trip that results in a [Balancing Contingency Event], the generator's telemetry is often invalid or suspect for some time, and if the [balancing authority] is unable to accurately quantify the actual MW loss, it may be required to take extreme actions, including shedding firm load, simply to meet the 90-minute contingency recovery requirement."[57] Joint Commenters claim that the "likelihood of such an occurrence of multiple independent generation losses absent a catastrophic transmission failure is also very low."[58] Joint Commenters state that on average, one generator is lost in the Eastern Interconnection every 7 to 8 days, and "the probability of four random large generator trips in the Eastern Interconnection in a two hour period was one in 350 years."[59]

43. BPA and Idaho Power support the Commission's proposal to require balancing authorities to restore contingency reserves within the 90-minute Contingency Event

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[56] CEA Comments at 4; *see also* IESO Comments at 5.

[57] Joint Commenters Comments at 5.

[58] *Id.*

[59] Joint Commenters Comments at 6 (citing a probability analysis performed during the Reliability Standard BAL-003-1 development process using frequency event data for January 2006 to September 2012).

Recovery Period and receive “credits” for megawatt losses during the Contingency Event Recovery Period. TVA believes the potential for unlimited resets of the 90-minute restoration period is “extremely remote,” but TVA supports the credit proposal as a “reasonable approach” for managing multiple events during a contingency restoration period.

Commission Determination

44. The Commission determines not to adopt the NOPR proposal that NERC modify Reliability Standard BAL-002-2 to establish a firm requirement that responsible entities must restore contingency reserves within the 90-minute Contingency Reserve Restoration Period. Based on the comments, we are satisfied that occurrences of multiple Balancing Contingency Events during the 90-minute restoration period are rare and would be temporally bounded by the Reporting ACE recovery requirements in Reliability Standard BAL-001-2. We also acknowledge NERC’s comment that intervening Balancing Contingency Events do not relieve balancing authorities and reserve sharing groups of their obligation to restore contingency reserves by the end of the reset period. Further, we acknowledge Joint Commenters’ concern that determining the amount of megawatt losses to “credit” could be a distraction from the contingency reserve restoration effort, and the benefits from the proposed “credit” approach could be offset by unnecessary load shedding caused by potential confusion and uncertainties associated with its implementation.

45. While, as stated in the NOPR, under some circumstances, extensions of the 90-minute Contingency Reserve Restoration Period may be appropriate, the comments do

not fully address the concern expressed in the NOPR with resets resulting from additional megawatt losses following a Reportable Balancing Contingency Event. Therefore, although we determine not to direct modifications to the Reliability Standard, we conclude that the automatic reset provision of Reliability Standard BAL-002-2, Requirement R3 should be monitored for potential problems.

46. Accordingly, the Commission directs NERC to collect and report data pertaining to: (1) additional megawatt losses following Reportable Balancing Contingency Events during the Contingency Reserve Restoration Period; and (2) the time periods for contingency reserve restoration under Requirement R3 and the number of resets of the 90-minute restoration period, and submit a report to the Commission two years following the first day of implementation of Requirement R3. After NERC reports on the data in a compliance filing, the Commission will consider what further action, if any, to take.

C. Exclusion of Megawatt Losses Above the Most Severe Single Contingency

NERC Petition

47. NERC's definition of Reportable Balancing Contingency Event limits balancing authority and reserve sharing group responsibility to megawatt losses between 80 percent and 100 percent of their most severe single contingency that occur within a one minute interval.[60] In its petition, NERC asserted that an "integrated and coordinated" suite of set of Reliability Standards (BAL-001-2, BAL-003-1, TOP-007-0, EOP-002-3, EOP-011-1,

[60] *See* NERC Petition, Ex. D (Implementation Plan) at 2.

IRO-008-2, and IRO-009-2) will address the "complex issues" resulting from exceedances of the most severe single contingency.[61]

NOPR

48. In the NOPR, the Commission expressed concern about the exclusion of megawatt losses above a responsible entity's most severe single contingency from the scope of Reliability Standard BAL-002-2. The Commission questioned the assumption that all such megawatt losses, however small, warrant the proposed limitation on Reliability Standard BAL-002-2.[62] Further, while recognizing the protections that the related set of Reliability Standards may provide in extreme circumstances, the Commission noted that megawatt exceedances of the most severe single contingency that do not cause energy emergencies or otherwise implicate the set of Reliability Standards cited by NERC could result in a reliability gap; they also could create the potential for balancing authorities to lean on the Interconnection by indefinitely relying on neighboring balancing authorities' resources.[63]

49. In the NOPR, the Commission did not propose a specific approach but, rather, sought comment on how to address this possible reliability gap and whether to impose a reasonable obligation for balancing authorities and reserve sharing groups to address

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[61] NERC Petition at 15.

[62] NOPR, 155 FERC ¶ 61,180 at P 33.

[63] *Id.*

scenarios involving megawatt losses above the most severe single contingency that do not cause energy emergencies. The NOPR stated that, based on the comments, the Commission may direct that NERC develop a new or modified Reliability Standard to address that reliability gap.[64]

Comments

50. NERC, EEI, NRECA, TVA, BPA, CEA, Joint Commenters, IESO, and APS assert that concerns about a possible reliability gap are unfounded and urge the Commission to approve Reliability Standard BAL-002-2 as filed. NERC maintains that the limitation on the scope of Reliability Standard BAL-002-2 will not create a reliability gap and reasserts its view that an integrated, coordinated suite of Reliability Standards "will address important reliability issues and prohibit entities from being able to 'lean' on the Interconnection when contingency events cause MW losses greater than an entity's MSSC."[65] NERC states that in situations involving megawatt losses above the most severe single contingency, reliability issues associated with ACE recovery and contingency reserve restoration become less important and other reliability issues "such as transmission line-loading issues or frequency deviations" create more immediate reliability threats and warrant priority status.[66]

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[64] *Id.* at 34.

[65] NERC Comments at 20 (citing Reliability Standards BAL-001-2, BAL-003-1, EOP-002-3, EOP-011-1, IRO-001-4, TOP-001-3, IRO-008-2, and IRO-009-2).

[66] *Id.*

51. EEI agrees with NERC, and also notes that exceedances of the most severe single contingency that do not create energy emergencies generally raise commercial, not reliability, issues. Further, EEI asserts that tightening Reliability Standard BAL-002-2 by requiring balancing authorities to address megawatt losses above the most severe single contingency "could have unintended consequences that limit the flexibility of the [reliability coordinators] and [balancing authorities] to work together under the existing suite of standards to address such complex situations..."[67]

52. Joint Commenters consider requiring balancing authorities and reserve sharing groups to address megawatt losses above the most severe single contingency as tantamount to requiring entities to operate to "N-2" or greater conditions. Joint Commenters assert that this would not only be expensive, estimating that doubling current contingency reserves across North America could cost $150-200 million/year based on average monthly cost of spinning reserves, it could adversely impact reliability. Joint Commenters state that N-2 events typically result from severe transmission events involving weather, major equipment or protection system failures. According to Joint Commenters, "[i]n these situations, transmission security takes priority over maintaining ACE to zero. Excessive generation dispatch by [balancing authorities] could interfere

[67] EEI Comments at 11-12.

with actions taken simultaneously by Transmission Operators and remote [balancing authorities] to resolve problems on the transmission system."[68]

53. Joint Commenters explain that the available data reflecting experience with megawatt losses subject to currently-effective Reliability Standard BAL-002-1 indicates that concerns about a reliability gap are overstated. According to Joint Commenters, of the 95 events involving most severe single contingency exceedances from 2012 to 2015, 91 were recovered in less than 15 minutes, and there were no Interconnected Reliability Operating Limit (IROL) exceedances of over 30 minutes in 2015, "which demonstrates that the grid was secure even while zero ACE was not achieved within 15 minutes."[69]

54. CEA and IESO also oppose requiring balancing authorities or reserve sharing groups to address megawatt losses exceeding the most severe single contingency, which they describe as an "open-ended requirement."[70] CEA explains that it "can severely affect a [balancing authority's] ability to suitably plan for potential contingency events. At an increased cost and at the expense of reduced market efficiency (more capacity is put aside for reserve as opposed to bidding into the energy market), a [balancing authority] could, in theory, design and operate to N-2, N-3 or greater events. However, this is simply not feasible."[71]

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[68] Joint Commenters Comments at 9.

[69] *Id.* at 8 (citing NERC's 2016 State of Reliability Report).

[70] CEA Comments at 5; IESO Comments at 7.

[71] CEA Comments at 5-6.

Commission Determination

55. The Commission remains concerned with relying on a "coordinated suite of standards," as NERC maintains, to address reliability issues associated with megawatt losses above the most severe single contingency, considering that these other Reliability Standards do not specifically address restoration of ACE and Contingency Reserves. Further, the requirements for emergency Operating Plans in Reliability Standard EOP-011-1 do not specify any obligation for a balancing authority, transmission system operator, and/or reliability coordinator to take action to return ACE to zero for all operating conditions.

56. Additionally, Reliability Standards TOP-001-3, EOP-003-2, IRO-008-2, and IRO-009-2 pertain to actions needed to prevent or mitigate SOLs/IROLs caused by transmission line loading and other responsibilities of the transmission system operator and reliability coordinator. These Reliability Standards do not specifically address the balancing authority's responsibility to recover ACE by balancing load and generation, the purpose of Reliability Standard BAL-002-2.

57. The Commission finds the arguments and historical data provided by commenters to be helpful regarding whether there is a need to expand the requirements of Reliability Standard BAL-002-2 to address most severe single contingency exceedances that do not cause energy emergencies, as contemplated in the NOPR. Nonetheless, we believe the comments do not fully resolve open questions regarding the potential reliability impact of suspending the focus on the balancing of demand and load and ACE recovery—the purpose of Reliability Standard BAL-002-2—in exceedance scenarios.

58. The Commission determines that it is important to better understand the potential impacts of the approach taken in Reliability Standard BAL-002-2 when megawatt losses exceed the most severe single contingency without causing an energy emergency. Accordingly, we direct NERC to study the reliability risks associated with most severe single contingency exceedances that do not cause energy emergencies and submit a report with findings to the Commission two years from Reliability Standard BAL-002-2 implementation.

D. Violation Risk Factor for Requirements R1 and R2

NERC Petition

59. NERC proposed a "medium" violation risk factor for each requirement of Reliability Standard BAL-002-2.

NOPR

60. In the NOPR, the Commission expressed concern that NERC did not adequately justify lowering the assignment of the violation risk factor for Requirements R1 and R2 and proposed to direct that NERC assign a "high" violation risk factor to Reliability Standard BAL-002-2, Requirements R1 and R2.

61. Requirement R1 requires a balancing authority or reserve sharing group to deploy contingency reserves in response to all Reportable Balancing Contingency Events as the means for recovering Reporting ACE. Requirement R2 requires a balancing authority or reserve sharing group to develop, review and maintain a process within its Operating Plans for determining its most severe single contingency and to prepare to have contingency reserves equal to, or greater than, its most severe single contingency.

Currently-effective Reliability Standard BAL-002-1 assigns a "high" violation risk factor for its Requirements R3 and R3.1, which NERC explained are analogous to proposed Requirements R1 and R2 in Reliability Standard BAL-002-2.[72]

62. In the NOPR, the Commission stated that NERC provided insufficient support for the proposed violation risk factor for Requirements R1 and R2. In justifying the assignment of a "medium" violation risk factor NERC asserted, without explanation, that a "medium" violation risk factor is "consistent with other reliability standards (i.e., BAL-001-2, BAL-003-1)."[73] NERC also contended, without explanation, that Requirement R3 is similar in concept to the current enforceable BAL-001-0.1a standard Requirements R1 and R2, which have an approved medium violation risk factor, and approved reliability standards BAL-001-1 and BAL-003-1.[74] The conclusory statements in NERC's petition regarding the alleged similarities between Requirements R1 and R2 and other Reliability Standards, the NOPR stated, do not adequately explain the alleged bases for reducing the violation risk factor for Requirements R1 and R2 from the analogous Requirement R3 in the currently-effective Reliability Standard.

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[72] NERC Petition, Ex. I (Mapping Document for BAL-002-2).

[73] NERC Petition, Ex. G (Analysis of Violation Risk Factors and Violation Severity Levels) at 4.

[74] *Id.*

Comments

63. NERC, EEI and APS oppose raising the violation risk factor for Reliability Standard BAL-002-2 to "high" as proposed in the NOPR. NERC asserts that a failure to perform Requirements R1 and R2 "in real time would produce results consistent with the Commission approved guidelines for a 'Medium' [violation risk factor] VRF … [that is] unlikely to lead to Bulk Electric System instability, separation, or cascading failures."[75] With regard to Requirement R1, NERC states that Reporting ACE "is not an immediate measure of reliability, and the risk resulting from failure to meet Requirement R1" is not likely to lead to instability, separation or cascading failures, the criteria for a high violation risk factor.[76] Likewise, NERC asserts that a "medium" violation risk factor is appropriate for Requirement R2, because the process responsible entities use for developing and reviewing their most severe single contingency "does not directly contribute to reliability."[77] EEI agrees, adding that it "also believes the medium VRF is justified because in most instances ACE is more reflective of commercial issues, particularly if frequency remains normal."[78]

64. APS also disagrees with the NOPR proposal because the Commission "utilizes previous versions of reliability standards as a benchmark for the acceptability of VRFs

[75] NERC Comments at 28.

[76] *Id.* at 29.

[77] *Id.* at 30.

[78] EEI at 13.

[violation risk factors]."[79] APS states that it is "concerned that the assignment of a VRF based solely on the previous VRF assignments may contravene the current NERC Rules of Procedure and associated processes."[80] APS recommends that the Commission direct NERC to reevaluate the VRFs for Reliability Standard BAL-002-2 "against existing guidance."[81]

Commission Determination

65. We adopt the NOPR proposal regarding the violation risk factor for Reliability Standard BAL-002-2, Requirements R1 and R2. According to the Commission-approved criteria, a "high" violation risk factor should be assigned to a Reliability Standard requirement if violating the requirement could "directly cause or contribute to the 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." Reliability Standard BAL-002-2, Requirement R1 requires responsible entities to recover Reporting ACE following the occurrence of a Reportable Balancing Contingency Event, which supports Interconnection frequency in real-time.

66. We disagree with NERC that significant real-time differences between actual and scheduled interchange, the imbalance that Requirement R1 is intended to address, do not

[79] APS Comments at 11.

[80] *Id.*

[81] *Id.*

fall within the scope of the criterion for a "high" violation risk factor. The need for the bulk electric system to stabilize after changes in system frequency is critical for real-time system operations. NERC asserts that the status of Reporting ACE "is not indicative of an immediate vulnerability."[82] We disagree. A violation of Requirement R1 jeopardizes system frequency, because it places the bulk electric system in a weakened operating condition with heightened risks of instability, separation, or cascading failures that could result from a second contingency.

67. With regard to Requirement R2, NERC acknowledges that actions under Requirement R2 "support Requirement R1 by requiring responsible entities to develop, review, and maintain a process to determine the MSSC and to maintain, for deployment under Requirement R1, at least enough Contingency Reserve to cover the MSSC…[Requirement R2] is critical to the implementation of proposed Reliability Standard BAL-002-2."[83] Nonetheless, NERC asserts that Requirement R2 "does not directly contribute to reliability."[84] We disagree, and conclude that the fundamental connection between Requirements R1 and R2 creates a significant role in maintaining reliability.

68. Accordingly, we direct NERC to assign a "high" violation risk factor to Reliability Standard BAL-002-2, Requirements R1 and R2.

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[82] NERC Comments at 29.

[83] *Id.* at 29.

[84] *Id.* at 30.

V. Information Collection Statement

69. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping (collections of information) imposed by an agency.[85] Upon approval of a collection(s) of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirements of this 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.

70. The Commission is submitting these reporting and recordkeeping requirements to OMB for its review and approval under section 3507(d) of the Paperwork Reduction Act of 1995, 44 U.S.C. § 3507(d) (2012). The NOPR solicited comments on the Commission's need for this information, whether the information will have practical utility, the accuracy of the provided burden estimate, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques. No comments were received.

71. This final rule approves revisions to Reliability Standard BAL-002-1. NERC states in its petition that the Reliability Standard applies to balancing authorities and reserve sharing groups, and is designed to ensure that these entities are able to recover from system contingencies by deploying adequate reserves to return their ACE to defined values and by replacing the capacity and energy lost due to generation or transmission

[85] 5 CFR 1320.11.

equipment outages. The Commission also approves NERC's seven new definitions and one proposed revised definition, and the retirement of currently-effective Reliability Standard BAL-002-1 immediately prior to the effective date of BAL-002-2.

72. Public Reporting Burden: Our estimate below regarding the number of respondents is based on the NERC Compliance Registry as of April 15, 2016. According to the NERC Compliance Registry, there are 70 balancing authorities in the Eastern Interconnection, 34 balancing authorities in the Western Interconnection and one balancing authority in the Electric Reliability Council of Texas (ERCOT). The Commission bases individual burden estimates on the time needed for balancing authorities and reserve sharing groups to maintain, annually, the operating process and operating plan that are required in the Reliability Standard. These burden estimates are consistent with estimates for similar tasks in other Commission-approved Reliability Standards. The following estimates relate to the requirements for this final rule in Docket No. RM16-7-000.

RM16-7-000 (BAL-002-2: Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event) [86]						
	Number of Respondents (1)	**Annual Number of Responses per Respondent (2)**	**Total Number of Responses (1)*(2)=(3)**	**Average Burden Hours & Cost Per Response [87] (4)**	**Total Annual Burden Hours & Total Annual Cost (3)*(4)=(5)**	**Cost per Respondent ($) (5)÷(1)**
BA/RSG:[88] Develop and Maintain annually, Operating Process and Operating Plans	105	1	105	8 $774	840 $81,262	$774
BA/RSG: Record Retention[89]	105	1	105	4 $112	420 $11,760	$112
TOTAL			**210**		**1,260** **$93,022**	**$886**

Title: FERC-725R, Mandatory Reliability Standard BAL-002-2.

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[86] Reliability Standard BAL-002-2 applies to balancing authorities and reserve sharing groups. However, the burden associated with the balancing authorities complying with Requirements R1and R3 is not included within this table because the Commission accounted for it under Commission-approved Reliability Standard BAL-002-1.

[87] The estimated hourly cost (salary plus benefits) of $96.71 is an average based on Bureau of Labor Statistics (BLS) information (http://www.bls.gov/oes/current/naics2_22.htm) for an electrical engineer ($64.29/hour) and a lawyer ($129.12).

[88] BA=Balancing Authority; RSG=Reserve Sharing Group.

[89] $28/hour, based on a Commission staff study of record retention burden cost.

Action: Collection of Information.

OMB Control No.: 1902-0268.

Respondents: Businesses or other for-profit institutions; not-for-profit institutions.

Frequency of Responses: On Occasion.

Necessity of the Information: This final rule approves Reliability Standard BAL-002-2, which is designed to ensure that a responsible entity, either a balancing authority or reserve sharing group, is able to recover from system contingencies by deploying adequate reserves to return its ACE to defined values and replacing the capacity and energy lost due to generation or transmission equipment outages. Reliability Standard BAL-002-2, Requirement R1 requires a responsible entity, either a balancing authority or reserve sharing group, experiencing a Reportable Balancing Contingency Event to deploy its contingency reserves to recover its ACE to certain prescribed values within the Contingency Event Recovery Period of 15 minutes. Requirement R2 requires a balancing authority or reserve sharing group to develop, review and maintain a process within its Operating Plans for determining its most severe single contingency and prepare to have contingency reserves equal to, or greater than, its most severe single contingency. Requirement R3 provides that, following a Reportable Balancing Contingency Event, the responsible entity shall restore its Contingency Reserve to at least its most severe single contingency, before the end of the Contingency Reserve Restoration Period of 90 minutes.

Internal Review: The Commission reviewed the Reliability Standard and has determined that it is necessary to implement section 215 of the FPA. The requirements of Reliability

Standard BAL-002-2 should conform to the Commission's expectation for generation and demand balance throughout the Eastern and Western Interconnections as well as within the ERCOT Region.

73. Interested persons may obtain information on the reporting requirements by contacting the following: 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].

VI. Environmental Analysis

74. 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.[90] 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 not substantially change the effect of the regulations being amended.[91] The actions proposed here fall within this categorical exclusion in the Commission's regulations.

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[90] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987).

[91] 18 CFR 380.4(a)(2)(ii).

VII. Regulatory Flexibility Act

75. The Regulatory Flexibility Act of 1980 (RFA)[92] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. As shown in the information collection section, the Reliability Standard applies to 105 entities. Comparison of the applicable entities with the Commission's small business data indicates that approximately 23[93] are small business entities.[94] Of these, the Commission estimates that approximately five percent, or one of these 23 small entities, will be affected by the new requirements of the Reliability Standard.

76. The Commission estimates that the small entities affected by Reliability Standard BAL-002-2 will incur an annual compliance cost of up to $20,355 (i.e., the cost of developing, and maintaining annually operating process and operating plans), resulting in a cost of approximately $885 per balancing authority and/or reserve sharing group. These costs represent an estimate of the costs a small entity could incur if the entity is identified as an applicable entity. The Commission does not consider the estimated cost per small entity to have a significant economic impact on a substantial number of small

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[92] 5 U.S.C. 601-612.

[93] 21.73 percent of the total number of affected entities.

[94] 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 final rule, 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).

entities. Accordingly, the Commission certifies that this final rule will not have a significant economic impact on a substantial number of small entities.

VIII. Document Availability

77. 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.

78. 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.

79. 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.

IX. Effective Date and Congressional Notification

80. 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 a “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.

APPENDIX

Commenters

Abbreviation	Commenter
APS	Arizona Public Service Company
BPA	Bonneville Power Administration
CEA	Canadian Electricity Association
EEI	Edison Electric Institute
Idaho Power	Idaho Power
IESO	Independent Electricity System Operator
Joint Commenters	Alberta Electric System Operator, California Independent System Operator, Electric Reliability Council of Texas, Inc., Midcontinent Independent System Operator, Inc., PJM Interconnection, L.L.C., Southwest Power Pool, Inc., and IESO
Naturener	Naturener USA, LLC
NERC	North American Electric Reliability Corporation
NRECA	National Rural Electric Cooperative Association
TVA	Tennessee Valley Authority

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

NOTICE OF EMERGENCY CLOSING

(February 8, 2017)

Due to logistical issues at the Commission's headquarters, the Commission is closing at 11:00 a.m. today. The emergency closing provisions issued December 18, 2003, in Order No. 645 under Docket No. RM04-3-000 will apply to today's closing.

Kimberly D. Bose,
Secretary.

February 8, 2017

News Media Contact
Mary O'Driscoll | 202-502-8680

No FERC Meeting for February

The Federal Energy Regulatory Commission (FERC) has canceled its February 16, 2017 agenda meeting, Acting Chairman Cheryl LaFleur and Commissioner Colette Honorable announced today. Acting Chairman LaFleur and Commissioner Honorable also have decided, in view of the lack of a quorum, to suspend subsequent monthly agenda meetings until further notice.

Unless otherwise announced, FERC will continue to hold previously scheduled meetings and events sponsored by FERC, including the joint meeting between FERC and the Nuclear Regulatory Commission on February 23, 2017, and the upcoming Hydropower Regulatory Efficiency Act of 2013 workshop on March 30, 2017. FERC also will continue to announce and schedule future meetings, technical conferences and workshops as appropriate.

R-17-22

(30)

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
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Proposed - 2017 NPCC Compliance Committee Meetings

Wednesday, January 18…conference call

Wednesday, February 15…conference call

March 14-15 (Tuesday, Weds) at NextEra, Juno Beach, FL

Wednesday, April 12…conference call

May 23-25, Compliance Workshop (Tuesday-Thur) Albany, NY

June 13-14 (Tuesday, Weds) at NPCC Boardroom.

Wednesday, July 12…CC conference call

Wednesday, August 16…CC conference call

September 19, 20 (Tuesday, Weds)…at IESO or Hydro One, Toronto

Wednesday, October 18…CC conference call

November 7-9, Compliance Workshop (Tuesday – Thurs) Hartford, CT

December 7 (Thurs)…Boston– after RCC and NPCC annual meetings

As discussed at 9/20/16 CC meeting at NPCC